State of Indiana
Indiana Utility Regulatory Commission

PETITION OF INDIANA GAS COMPANY, INC. d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN NORTH") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO TRACK ITS UNACCOUNTED FOR GAS COSTS AND THE GAS COST COMPONENT OF ITS BAD DEBT EXPENSE IN ITS GAS COST ADJUSTMENT FILINGS; (4) APPROVAL OF A DISTRIBUTION REPLACEMENT ADJUSTMENT TO RECOVER THE COSTS OF A PROGRAM FOR THE ACCELERATED REPLACEMENT OF CAST IRON MAINS AND BARE STEEL MAINS AND SERVICE LINES; (5) APPROVAL OF REVISIONS TO THE SALES RECONCILIATION COMPONENT OF THE ENERGY EFFICIENCY RIDER APPROVED IN CAUSE NOS. 42943 AND 43046 TO PROVIDE FOR RECOVERY OF 100% OF THE DIFFERENCE BETWEEN ACTUAL AND APPROVED MARGINS; (6) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR GAS SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES; AND (7) CONSIDERATION AND APPROVAL IN PHASE II OF THE PROCEEDING OF AN ALTERNATIVE REGULATORY PLAN FOR A REVENUE STABILIZATION PLAN	)	FILED MAY 1 8 2007 INDIANA UTILITY REGULATORY COMMISSION CAUSE NO. 43298

VECTREN

Prepared Direct Testimony and Exhibits
of
Indiana Gas Company, Inc.
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(Vectren North)

Book 1 of 3

JA Benkert, MS Hardwick, PR Moul, RL Goocher, DA Karl

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INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

IURC CAUSE NO. 43298

DIRECT TESTIMONY
OF
JEROME A. BENKERT, JR.
EXECUTIVE VICE PRESIDENT AND CFO

ON

OVERVIEW OF CASE

SPONSORING PETITIONER'S EXHIBIT JAB-1

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerome A. Benkert. My business address is One Vectren Square, Evansville, IN 47708.

Q. What is your position with Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North" or "Company")?

A. I am Executive Vice President and CFO of Vectren North. I also hold this same position with Vectren Corporation ("Vectren"), Vectren Utility Holdings, Inc. ("VUHI"), Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery, Inc. ("Vectren South") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. What is your educational background?

A. I graduated from Indiana University in 1980 obtaining a Bachelor of Science degree with a concentration in accounting.

Q. Please describe your business experience.

A. I have over 20 years experience in various executive, financial and administrative roles, primarily in the utility and energy industry. I have worked at Vectren and its predecessor companies in a variety of positions including Assistant Treasurer, Vice President and Controller, and Executive Vice President and COO of Indiana Energy's administrative services company. Since Vectren's formation I have held the position of Executive Vice President and CFO and for a brief period, Treasurer. I began my career as a CPA with five years of public accounting. I am a director of VUHI, Vectren North, Vectren South, and Vectren Ohio, as well as a number of Vectren's non-regulated subsidiaries and affiliates. In addition, I have also been appointed to the Board of Directors of Fifth Third Bank, Indiana (Southern) and Deaconess Hospital of Evansville, Indiana.

Q. What are your responsibilities as CFO of Vectren and its regulated subsidiaries?

A. As an executive officer I am responsible for strategic direction, policy and governance. In my role as CFO, I am responsible for capital attraction and risk management. Functional areas reporting to me include Treasury, Investor Relations, Accounting and Tax, and Regulatory Affairs and Fuels.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will provide an overview of the request in this case. Vectren North has continued to make significant investments in the infrastructure and facilities necessary to provide reliable service to customers since its last rate case filed in 2004. It is this rate base investment, which is not reflected in current rates, that is a driver of well over half of the requested increase of this case. Over that same period, Vectren North has also incurred increases in the costs of material, labor, services and other items.

Apart from rate base growth, which includes both a new 24 mile pipeline to serve the Greensburg area and the new Honda plant, as well as a new 15 mile pipeline to serve our Greencastle system, this case reflects a proposal to address the aging workforce dilemma resulting from the wave of retirements of the baby boomer generation. Also, our operations personnel have identified areas where the condition of aging facilities can be improved through inspection, painting and maintenance programs. These programs should increase the life of our facilities and support continued reliability.

I will also testify about Vectren North's weighted average cost of capital and the business risks facing the Company. To attract capital on a favorable basis and support solid credit ratings, Vectren North has taken steps to maintain a strong balance sheet and finance its utility investment with the proper balance of long-term debt and common equity.

My testimony will cover the Bare Steel/Cast Iron Pipeline Replacement Program. This infrastructure program eliminates our oldest, leakiest pipe on an accelerated basis, and thereby improves reliability, safety, and operational efficiency.

Last, I will explain "Phase Two" of this proceeding as proposed in our Petition. Essentially, upon conclusion of this base rate case, we propose initiation of further proceedings for consideration of a revenue stabilization mechanism, similar to that adopted in several other states, which provides more predictable year over year financial performance, and ongoing periodic cost review via a cooperative effort between the utility and regulators. As explained, while Phase Two relates to the base rate case, it is a separate topic to be evaluated subsequent to issuance of a rate order.

OVERVIEW OF CASE

Q. Please describe the business of Vectren North.

A. Vectren North is a public utility supplying natural gas and natural gas transportation service to the public. Among other things, Vectren North owns, operates, manages and controls plant, property, equipment and other facilities used and useful for the acquisition, storage, transmission, transportation, distribution and sale of natural gas to residential, commercial, industrial and other customers in 49 counties in Central and Southern Indiana. The Company provides natural gas distribution service to over 565,000 customers in 49 counties throughout central and southern Indiana. Throughput to these customers in 2006 was represented by approximately 36% to residential customers, approximately 17% to commercial customers, and approximately 47% to industrial customers. Industrial customers comprise just 849 customers, or less than one-quarter of one percent of the Company's customers. This means that the energy needs of a few customers will have a significant impact on the Company's operations.

Q. Please explain the organizational structure of Vectren and VUHI, and describe the services provided to Vectren North by VUHI and Vectren.

A. Vectren is the publicly traded parent company of Vectren North formed by the merger of SIGCORP, Inc. and Indiana Energy, Inc. in March 2000. On October 31, 2000, Vectren acquired the gas distribution assets of the Dayton Power and Light Company. Vectren's three utility subsidiaries provide regulated gas and electric services to over one million customers in Indiana and Ohio. Vectren also has a number of non-regulated subsidiaries and investments that engage in energy marketing, coal mining, and other energy related activities. Certain administrative functions such as accounting and human resources are performed by Vectren personnel on behalf of Vectren North.

VUHI is an intermediate holding company wholly owned by Vectren. Apart from holding Vectren's equity interest in three utilities (Vectren North, Vectren Ohio and Vectren North), VUHI provides "shared services" to the utilities derived from the use of assets such as the information technology resources used to maintain customer records and the call center used to handle customer calls. VUHI has also received Commission approval to provide financing to the utilities. By pooling the financing requirements of its utility subsidiaries, VUHI is able to raise funds more efficiently, and on more attractive terms. This reduction in financing costs benefits customers. The cost of long term debt is reduced which creates annual interest savings of which flows directly and entirely to customers through this filing.

Q. What is Vectren North Gas requesting in this case?

A. Vectren North is requesting a revenue increase of $41.1 million or about 5% on total revenue.

Q. Please generally describe why Vectren North requires a rate increase at this time.

A. In 2004, when the current rates were established, Vectren North had an original cost rate base of $707.8 million. In this case, Vectren North seeks to recover a return on a rate base of $790.5 million, an increase in net investment of $82.7 million, or 11.7%.

In addition, Vectren North pays as an annual operating expense an Asset Charge of $15.6 million to VUHI. The Asset Charge represents investment in assets necessary to operate the utility. This payment to VUHI recognizes that VUHI has a net investment of $138 million in Information Technology, Call Center and other assets, to provide services to Vectren North, as well as to the two other Vectren owned utilities – Vectren North and Vectren Ohio. The Asset Charge paid by Vectren North represents its 39% share of this allocated expense. Vectren North Witness M. Susan Hardwick provides more detail on these amounts. By "sharing" these assets among the utilities, rather than each utility investing in duplicate assets, efficiencies are gained and customer rates are lower. The point here is that this "expense" is really akin to additional rate base investment to serve customers.

This increasing investment has been supported by Vectren's commitment to maintaining a financially solid company. In this case Vectren has maintained a capital structure of approximately 50% equity, about the same level as the last Vectren North case. While maintaining a financially solid company, significant debt refinancing has been achieved since the last case as described by Vectren North Witness Robert L. Goocher which lowers the annual debt financing cost by $2.2 million annually.

At the same time, Vectren North has prudently managed its total operating and maintenance expenses since 2004. Reliability programs, aging workforce related costs, and system improvement costs are pro forma O&M expenses proposed in this case that were not considered in the prior case. Combined, they represent a large portion of the pro forma O&M increase requested in this case. If we examine them separately, O&M expenses (not considering the Asset Charge) have grown by just over 2% since the last rate case in 2004. Analyzing it this way, it becomes apparent that this rate case is largely a case to set new rates to reflect an appropriate return on the Company's increased level of investment in utility plant and assets used to serve customers, and to address costs associated with the new programs that will be reviewed in this case.

Q. You specifically mentioned reliability programs, aging workforce related costs and system improvements as being an important part of this case. Please explain.

A. Each of these areas represent new costs not contemplated in the 2004 case. I mentioned them in the context of Vectren North's pro forma O&M expenses because, on an initial review, it appears as though Vectren North's O&M expenses have risen significantly in the past three years. In reality, they have been held below inflation rates. But, reliability programs, aging workforce costs, and system improvement costs are requested as incremental costs from 2004. Additionally, energy efficiency costs of over $3 million are included to pursue the program approved by the Commission and overseen by the Collaborative as described further by Vectren North Witness Douglas A. Karl.

Since 2004, Vectren North has undertaken a review of its operational practices, with reference to industry best practices, with the objective of improving overall reliability. There have been organizational enhancements focused on bringing specific skill-sets into key processes and positions in gas engineering and gas dispatching. There have been key capital investments in both distribution and transmission infrastructure and a move toward greater emphasis on preventative maintenance programs, while also integrating increased use of technology to collect data on our facilities to help direct maintenance efforts. In this case we propose to enhance our maintenance and reliability efforts through programs with an annual cost of almost $5 million as covered primarily by Vectren North Witness Eric L. Schach in his direct testimony.

Aging workforce is perhaps the most serious challenge faced by the utility industry as a whole and certainly Vectren North. As a member of Senior Management I have personally participated in numerous discussions involving key representatives of our Human Resources and Operations areas where this topic has received attention. We have studied the issue in depth, benefiting from information and ideas other companies have developed as they react to the changing demographics of the workforce.

Vectren North Witness William S. Doty will address how we intend to replace these valuable employees. What I want to emphasize is that Vectren North is taking this issue very seriously and is spending the time necessary to thoughtfully respond to the issue. Further, Vectren North will use the requested cost recovery to hire qualified men and women to replace the retirees consistent with the plans set forth in this case. We ask the Commission to support these important efforts. We are essentially laying the foundation of our future ability to operate reliably by hiring these employees now and spending the requisite time to adequately train them to perform their jobs.

Recent federal legislation to enhance public safety has created the need to conduct far more assessments of high-pressure pipe condition and is resulting in incremental operating costs not previously incurred. Further requirements related to distribution integrity will be forth coming. In this setting, accelerating replacement of the oldest parts of our system makes sense. Details regarding the proposed ratemaking for this replacement program are discussed by Vectren North Witness James M. Francis. (See Petitioner's Exhibit JMF-1).

Q: Are there any cost reductions available to offset a portion of the proposed rate increase?

A: Yes. Beginning April 1, 2007, Vectren North's annual pipeline demand costs decreased by over $16 million. This decrease in the cost of the pipeline capacity portfolio resulted from shedding capacity contracts due to reduced customer demand, and savings provided by our portfolio administrator. The demand cost savings result in lower GCA costs to our customers.

FINANCIAL PERFORMANCE

Q. Please provide a summary of Vectren North's financial performance since its last rate case.

A. In March 2004, Vectren North filed its first rate case since receiving a base rate order in 1992. From 1992 to 2004, Vectren North's rate base increased by $270 million or 46%. In its 2004 case, Vectren North's O&M had only grown by the annual amount of $2.8 million over the 12 year period. On November 30, 2004, the Commission approved a Settlement providing for a 10.6% return on equity and a revenue increase of 3.4%.

As shown in its GCA filings, since implementing these new base rates Vectren North has not earned its authorized Net Operating Income. For the nine GCA quarters since November 2004, the GCA earnings test reflects that Vectren North has under earned by more than $10 million. And this shortfall was computed using an unchanging NOI level even while rate base investment has grown as demonstrated in this case.

Q. Why has Vectren North struggled financially since obtaining new rates?

A. Customer consumption declined significantly during this period. Because Vectren North had volumetric rates, this meant that Vectren North had no realistic opportunity to achieve its authorized level of cost recovery. This situation has been addressed in large part through the approval in late 2006 of the Efficiency Settlement that also provided for the change in rate design necessary to remove the link between usage and cost recovery. However, with the growth in investment and rise in other costs, Vectren North will still not be able to achieve its authorized return absent a rate increase.

CAPITAL ATTRACTION AND REQUESTED RETURN ON RATE BASE

Q. Please discuss the return on capital requested by Vectren North in this case.

A. The requested overall return on original cost rate base is 8.43% as set out in the testimony and exhibits of Vectren North Witness Robert L. Goocher. It essentially remains unchanged from our current authorized return of 8.38%. While Vectren North Witness Goocher describes these matters in some detail, I support as a matter of policy our goal of improving over time Vectren North's credit ratings to the "A" level from the current split ratings of "Baa1" from Moody's and "A-" from Standard and Poors. And while Vectren North's equity component has held steady at about 49% of ratemaking capital and the capitalization as presented for ratemaking demonstrates responsible financial management, the capital spending needs for Vectren North and Vectren's other utilities require Vectren to enter the market and attract new equity as well as new debt capital. Most recently Vectren sold 4.6 million shares, about $130 million of new equity in February 2007 to support the regulated businesses.

Q. What return on equity is requested in this case?

A. Vectren requests a return on equity of 11.5% in this case as supported by the testimony of Vectren North Witness Paul R. Moul. (See Petitioner's Exhibit PRM-1). Vectren North Witness Moul, in arriving at his recommendation, has considered four different methodologies to determine a reasonable return as well as risks specific to Vectren North. In this regard, I will provide further discussion of risk factors within my testimony.

Q. Is Vectren North's request for a return above 11% a reasonable request?

A. Yes. In the last 2 ½ years, 13 LDCs have received authorized returns of 11% or higher. This does not count LDCs that may have incentive plans that allow for higher returns.

SYSTEM IMPROVEMENTS

Q. Has the gas pipeline system condition become a focal point for regulators in recent years?

A. Yes. Four years ago, Congress passed the Pipeline Safety Improvement Act of 2002 requiring the U. S. Department of Transportation (DOT) to create rules to require all pipeline generators to assess their high pressure non-distribution lines in certain areas, essentially tied to density of population. This newly required integrity assessment activity has begun.

Currently, the DOT is working on similar rules related to distribution pipeline integrity. These rules are anticipated to be finalized in 2007. Apart from the DOT rules, some states have ordered gas utilities to engage in programs to replace older pipes.

These events stem from both highly publicized incidents involving pipelines that have led to loss of property and life, as well as a growing awareness that the pipeline infrastructure currently being relied upon contains many miles of older pipe installed prior to the advent of better materials and construction methods. In fact, many bare steel and cast iron pipelines still in use today have not been allowed for new installations since DOT first put minimum pipeline safety standards in place in 1971.

Q. Please explain why Vectren North seeks timely cost recovery associated with the accelerated replacement of these older pipes.

A. As discussed in detail by Vectren North Witness James M. Francis, Vectren North believes that aggressively removing these pipes from service will be beneficial to ongoing system reliability and cost savings. The Distribution Replacement Adjustment ("DRA") tracker proposal, modeled on a similar approach approved by the Ohio Public Utilities Commission to enable Cincinnati Gas & Electric Company to proceed with a more aggressive replacement program than the one proposed here, provides support for capital investment similar to the type of support provided with respect to electric utility expenditures on pollution control equipment. Vectren North's rate base in this case is approximately $790 million. In order to replace all bare steel and cast iron lines, during the planned 20 year program Vectren North may invest as much as $345 million or more. Such a substantial under taking - incremental to the typical capital requirements to operate the system which will not go away - requires the Company to raise additional debt and equity to accomplish the objectives of this important system improvement. Timely recovery of invested costs is needed to embark on this effort. Therefore, the DRA tracker, which will be subject to annual reviews of both expenditures and the next year of proposed projects, as well as offsets for operating cost savings resulting from the project, provides needed financial support for the project.

Q. How does the requested cost recovery relate to the GCA NOI earnings test?

A. Vectren North's recovery of its financing costs will only support this planned investment if such recoveries are not refunded to customers. By analogy, when Vectren's electric utility obtains timely recovery of the costs to invest in clean coal technology, such recoveries are added to the FAC earnings test to avoid the situation where the recovery of project costs create "over earnings" subject to refund. The bare steel replacement program, much like the installation of environmental equipment on generation, does not produce revenue but does serve the public good. Like the recovery of the environmental project costs, recovery of the pipeline replacement costs should be added to authorized NOI in the GCA so that such recovery does not cause excess earnings under the statutory NOI earnings test.

SALES RECONCILIATION COMPONENT

Q: Please explain the Sales Reconciliation Component approved in Cause No. 42493.

A: As discussed earlier, in August of 2006, the IURC approved a transforming energy efficiency program for Vectren North. The program provides for the implementation of an Energy Efficiency Rider which is comprised of an Energy Efficiency Funding Component (EEFC) and a Sales Reconciliation Component (SRC). The SRC provides Vectren North with an improved opportunity to collect the base rate revenue requirement established by the Commission for the Residential and General Service customer classes. The SRC is designed to encourage proactive and good faith efforts by the Company to promote programs designed to reduce customer use of natural gas. For each of the smaller customer classes, Vectren recovers the margin difference between actual margin and the margin approved in the most recent rate case, as adjusted for customer additions or reductions. Vectren North Witness Douglas A. Karl provides an update on the implementation of the efficiency program. Because the SRC was approved between rate cases without an opportunity to fully review the implications on Vectren's overall financial performance, recovery of the margin difference was set at 85%.

Q: Should Vectren North collect 100% of its margin difference for these customer classes subsequent to this rate case?

A: Yes. The Order in Cause No. 42943 contemplated a future rate case and thus the missing opportunity to review financial performance and business risk. In that case, I testified that recovery of 85% of margins represented a sufficient level of fixed cost recovery on an interim basis to support the culture change to an "efficiency first" Company, until the Commission had an opportunity to review the complete financial performance of the Company. As explained by another party in that case, in the long term 100% margin recovery provides the best and most appropriate incentive for the Company to encourage reduced customer usage. This is the natural and appropriate time to do that review and provide for full recovery of lost margins for the impacted customer classes once new rates and a new ROE are established.

Q. The Normal Temperature Adjustment ("NTA") and the approval of the Efficiency Settlement in Cause No. 42943 address the uncertainty associated with volumetric rate design with respect to residential and commercial customers. Is this change detrimental to customers?

A. No. Our customers benefit by paying a stable charge whether the weather is cold or warm and, our customers benefit from the efficiency programs. Further, customers benefit when the utility produces stable cash flows, financial results and attendant strong credit ratings.

For decades, Vectren North billed customers using volumetric rates. For the earlier portion of this period, this rate design did not pose asymmetrical risk to the Company due to more stable usage patterns and sales growth. Thus, the Company had a reasonable opportunity to recover its costs, including a reasonable return, over time. Under a lower gas cost environment, there was better opportunity to maintain or grow gas margins and to limit or control cost increases. Thus, while volumetric rate design inherently posed the risk that sales would not be at the level projected in the rate case, this rate design risk was symmetrical in nature.

A number of factors have undermined this symmetry over the past 5 years or so. As described in the Efficiency Settlement, greater efficiency in homes and appliances has driven customer use consistently downward and at greater rates of decline. This trend existed before the price spikes commenced in 1999/2000. But, gas prices and volatility have escalated this downward trend over the last two years, resulting in dramatic sales declines. High gas costs have also increased interest expense and bad debt expense and other costs. The result has been that more and more financial risk had been shifted to Vectren North over this period - yet higher returns have not been achieved as compensation for such risk that is tied to use of traditional volumetric rate design.

Q. If the objective of rate design is to create rates that provide a reasonable opportunity for Vectren North to recover its authorized costs, should the NTA and approval of the Efficiency Settlement result in a reduction to Vectren North's authorized cost of capital?

A. No. As a practical matter, it would be very difficult to increase returns to a level sufficient to fully compensate for volumetric rate design that can cause a gas utility in a period of declining sales to miss its level of authorized cost recovery by millions of dollars in a given year. Of late, this situation has gotten much worse given even more significant reduction in usage per customer.

Moreover, if rate design should serve the purpose of accurately providing a fair opportunity to recover an approved level of costs, then traditional volumetric rate design must be considered a poor tool for achieving this outcome. Replacing such an imperfect rate design with a more accurate mechanism does not harm customers and does not diminish utility business risk in a manner that justifies reducing its cost of capital. Actual recovery of reasonable fixed costs cannot be viewed as harmful to customers. Moreover, utilities should not be punished for proactively moving to a model of <u>promoting</u> conservation and usage declines to the benefit of their customers. Vectren North has competed for capital for years with many utilities that had NTAs. And the peer group utilized by Vectren North Witness Paul R. Moul for preparation of our cost of equity request is replete with many examples of weather, usage and other risk mitigation regulatory designs. Yet, Vectren North's allowed return on equity was no higher than its peers that had NTAs. For example, Vectren North's current allowed return of 10.6% is lower than that of Atlanta Gas Light, a gas utility that has fixed variable (non-volumetric) rates and does not sell gas to its customers, thereby avoiding many risks associated with providing gas supply.

Ultimately, a rate design that provides a more accurate means of providing cost recovery recognizes the nature of the gas distribution business as a largely fixed cost enterprise. Correcting faulty rate design still leaves Vectren North facing many other business challenges that are typical in the gas industry.

Finally, if weather over the last few years still, on average, reflected the 30 year average used in ratemaking, and normalized customer usage still tended to be fairly stable from year to year, then volumetric rates could over time even out because in some cold years, LDCs would potentially exceed this authorized level of return and in warmer years they would likely under earn. Over time, investors would expect these conditions to even out. The NTA and SRC stabilize margins, as a result upside is gone as well as downside. So, if the winter of 2007/2008 turns cold, increased usage will not create "financial windfall" for the Company. In this neutral setting, risk has been removed for customers and the Company, and more current circumstances have been recognized. This regulatory improvement does not translate to lowering returns.

Q. Apart from ongoing challenges associated with high and volatile gas costs discussed above, are there additional challenges that Vectren North seeks to address in this proceeding to support its continued provision of reliable service to its customers?

A. Yes. As discussed earlier, in this proceeding Vectren North will make proactive proposals to address two significant issues that have received growing attention from the entire energy industry --- (1) an aging workforce nearing retirement in a concentrated time period, and (2) aging infrastructure that results in high leak rates and should be replaced. Vectren North has considered how best to address these issues in an effective manner that avoids negative impact to the Company and its customers. Getting out in front of both of these issues is very much in the interest of the Company's customers.

<u>DISCUSSION OF RISK FACTORS</u>

<u>Demand Destruction</u>

Q. With the implementation of decoupling, is demand destruction still a concern for Vectren?

A. Yes. Together, the NTA and the SRC address margin volatility associated with residential and small commercial customers. While the SRC addresses declining sales per residential and commercial customer, no regulatory mechanism exists to address residential or large customer fuel switching or large customers going out of business or reducing gas usage. Less than a decade ago, gas utilities served the asphalt and grain drying industry. That service relationship no longer exists because gas is too expensive for these businesses. Given less than 850 large customers represent 47% of Vectren North's throughput, North is particularly exposed to loss of large customer margin.

Further, these mechanisms do not address changes in operating and maintenance costs, nor return on new investment, nor increased interest rates among other business risks. They simply improve on volumetric rate design and recognize the trend of warm winters and declining sales and importantly, allow the Company to advocate and sponsor conservation to reduce usage among Vectren North's customers.

<u>Volatile Gas Prices</u>

Q. The GCA process allows Vectren North to adjust its rates monthly in order to pass through commodity gas cost increases and decreases to customers. Given this cost tracking ability, does commodity market price volatility affect Vectren North?

A. Yes. High gas prices threaten cost competitiveness and create a potential dilemma where gas utilities lose customers without losing fixed costs, making it harder to spread costs and retain remaining customers. Gas prices hurt customer satisfaction and drive up operating costs, but in the long run, the threat to cost competitiveness represents a serious concern for all gas utilities. In the short-term, efficiency programs must be pursued to relieve supply pressure and reduce prices. In the meantime, in the present era, where a hurricane or a cold week can drive gas prices well above $10 per dth, the gas distribution business is more risky than it has ever been.

To protect customers from prevailing gas market volatility, Vectren North continues to use a portfolio approach to gas purchasing designed to help mitigate gas price volatility. This includes its advanced purchases at fixed prices, storage injections as well as some financial hedging. These efforts have been highly successful, but the market has seen unprecedented spikes in price, and as a result customers have incurred higher gas costs over the past few years.

This price volatility also has numerous intangible impacts. Higher and more volatile gas prices create customer dissatisfaction and difficulties with paying bills with

Vectren North, even though these prices are a national issue stemming from supply and demand factors that cannot be controlled by Vectren North. In addition, higher gas prices result in higher call volumes at our call center related to verifying meter readings and working out extended payment arrangements for customers, thus requiring employee overtime, additional employees or contractors and reducing employees' ability to address other business issues.

Customer Retention/Growth

Q. Please explain why retention of existing large and small gas customers and attraction of new gas customers have become a significant challenge for Vectren North.

A. With respect to our largest customers, the Indiana statute protecting us from bypass has been preempted based on a federal district court decision issued in 2001. As a result, larger gas customers can now legally be connected directly to an interstate pipeline, thereby eliminating Vectren North's distribution role. The result is that Vectren North now can lose existing or potential customers, due to bypass, and in order to compete with the pipeline, it may need to reduce its rates, thereby obtaining reduced margin. Three such cases involving discounted rate contracts to avoid bypass are pending before the Commission.

At the same time, the volatility of gas prices has a continuing negative effect on the use of gas as a preferred fuel. Residential customers may switch to electricity to avoid the unpredictability of gas bills. Larger customers have even more alternative fuel options, which now are more cost competitive and, if less volatile, allow for better budgeting of expenses. These customers may also choose to reduce operating levels during periods of higher prices, or worse, may shut down operations which are no longer cost competitive. Home builders may favor electricity if home owner gas costs are viewed as a detriment to home sales. Reduced gas use by large customers lowers revenues and diminishes our ability to maintain low rates for our remaining customers. Ultimately, as we incur capital costs to extend or replace our facilities, if growth declines or the retention problem increases, we will not receive incremental revenue to sufficiently fund such expenditures, and the Company's need for financing will only increase.

Environmental Regulations

Q. You identified increased environmental risks as another factor Vectren North faces.

A. Vectren North (or its predecessors) either owns, or at one time operated, 26 former manufactured gas plants (MGPs) located in Indiana. These operations left behind tar residue at these sites. Vectren North began reviewing its potential remediation obligation with respect to these sites in the early 1990's. Given the potential magnitude of the costs to remediate, Vectren North pursued rate recovery of the costs, as well as insurance recoveries and contributions from other potentially responsible parties ("PRPs") who either owned or operated these MGPs in the past.

The IURC denied rate recovery as a viable option in 1995 (Cause No. 39353, Phase II, 5/3/95), although it did indicate that given the remediation risk faced by the Company, an upward adjustment to ROE in its next rate case should be considered.

Vectren North pursued the other sources of cost contribution, and obtained insurance recoveries and agreements with PRPs with respect to certain MGP sites. Vectren North has used these funds to begin the remediation process at some sites. On July 31, 2000 Vectren North entered 17 MGP sites into the Indiana Department of Environmental Management's ("IDEM") Voluntary Remediation Program ("VRP"). That Voluntary Remediation Agreement was renewed in 2003 for 15 of the 17 sites. Also in 2003 PSI (now Duke Energy Indiana) enrolled four additional former manufactured gas plant sites in IDEM's VRP program for which Vectren North is a party to a cost sharing agreement as a potentially responsible party.

While Vectren North has remediated a number of sites, many remain to be remediated. The cost to perform site remediation has risen over time, in part due to tort litigation regarding air emissions occurring as a result of remediation activities. As each site is investigated, more data regarding site conditions is discovered, sometimes revealing that the scope of site remediation is greater than anticipated. In addition, environmental standards continue to evolve. Thus, while Vectren North has available only a fixed level of remaining insurance recovery dollars to fund MGP remediation, Vectren North can only estimate the potential magnitude of the costs to remediate the remaining MGPs at this time. As with any large scale environmental clean up project, the risks regarding the level of costs to be incurred are high.

Risk Factor Summary

Q. Does Vectren North need to respond to the various risks and changed circumstances you have described above?

A. Yes. Prudent management of our business requires that we recognize the significant change in the financial markets, and if possible address the specific concerns and risk factors weighing heavily on debt and equity investors' minds at this time. The consistent theme permeating the recent actions by the credit rating agencies and other market segments is an overriding desire for earnings stability and certainty. We believe it is in both the Company's and our customers' interest to respond to these concerns in a positive manner in order to continue to attract capital at favorable rates.

Bad Debt And Unaccounted For Gas Expenses

Q. Does Vectren North propose to use the GCA to track changes related to bad debt and unaccounted for gas cost expenses?

A. Yes. Given the current high cost of natural gas and the volatility that is expected to continue in the future, tracking unaccounted for gas (UAFG) and the gas cost component of bad debts is proposed as the best answer for both the customer and Vectren North. UAFG is a gas cost and is uncertain in amount largely due to price changes. Similarly, because approximately 70% of customer bills are gas costs, today the majority of bad debts consist of gas costs. These gas costs should be part of the gas cost recovery mechanism. Just like the GCA, as these costs fluctuate in the future, customers will not pay more or less than the Company actually incurs for these items. In an era of highly volatile gas prices, this is the right answer due to the inability to set a base rate level reflective of future prices.

Performance Pay

Q. Vectren North Witness M. Susan Hardwick has included in Vectren North Gas' pro forma adjustments the cost to the Company of Vectren's long term and short term performance pay plans. Please explain why these plans are necessary to attract and retain qualified employees.

A. Our employee performance pay plans are designed to attract, retain and motivate quality people in the Vectren workforce. The level of performance pay expense is developed from market data coming from various sources, including the American Gas Association ("AGA") annual compensation surveys as well as information from our compensation consultants, Hay Group and Towers Perrin. These sources enable us to compare compensation on both a regional and national basis. Important to our approach to performance payments are the behaviors upon which we focus. We have specific measures in areas such as safety, customer service and cost containment. Our belief is that our performance pay plan positively rewards people to work safely, meet their budgets (to affect earnings) and deliver exceptional customer service. There are specific targets and metrics in each of these areas. As discussed by Vectren North Witness William S. Doty, we do expect increased retirements due to an aging workforce, but as a result of our compensation approach and overall positive work environment, excluding retirements we experience a very low turnover of personnel which results in a more efficient expenditure of training dollars. These plans impact all of our employees. They are part of compensation and benefits negotiated for by the Vectren North bargaining unit employees. The performance pay that helps attract, retain and motivate our tenured/highly skilled workforce also offers great benefit to our customers as well as our shareholders, in terms of safe and reliable operations. Offering competitive compensation has never been more important as we respond to the aging workforce and the holes it can potentially leave in our bargaining and non-bargaining workforce.

Q. How does Vectren North Gas compensation levels and programs compare to comparable utilities and the market in general?

A. Based upon compensation surveys conducted by the AGA, Hay Group and Towers Perrin, we generally find our base pay/wages to be slightly below average. However, total compensation is generally at the market's average with the utilization of performance pay to motivate positive employee behaviors making up the difference. As a result, the performance pay is clearly "pay at risk". In other words, based on market data, Vectren employees would have higher base compensation. Management has chosen to put "at risk" an increment of this base pay through incentives. If the target level is met, performance pay is needed simply to bring the employees pay to market average. Our performance pay is paid only when specific performance objectives are met. Unlike base pay/wages, performance pay is not guaranteed. "Pay at risk" objectives include safety, customer service and cost control, which translates into earnings. Our analysis of compensation levels and programs included the AGA survey, a national survey that is specifically focused on utility positions closely matched in scope and responsibility. We also utilized recent Towers Perrin survey data that was drawn from over 100 utility/energy companies. They also provided general industry compensation data from over 750 companies. The Hay Group data provides an additional 30 utility/energy companies. The Vectren philosophy utilized in the Towers Perrin and Hay Group work states that base salary and annual performance pay will be "competitive with the 50th percentile of a blend of comparably-sized utilities and general industry companies."

Q. How do the targeted performance pay amounts included by Vectren North Witness M. Susan Hardwick in operating expenses compare to the total available amount of performance pay?

A. The performance pay plan design contemplates three levels of rewards: threshold, target, and maximum. For non-executives and executives alike, Company objectives achieved at or below the threshold metrics yield zero performance pay for participants. The plan design allows a linear progression from zero (threshold) to pay out at target levels, which is the amount included in the labor expenses supported by Vectren North Witness M. Susan Hardwick. Achievements above target are leveraged differently for non-executives than executives, and reflect the respective market data that determine total compensation for each group. For non-executives, there is a linear progression, from 100% at target to 150% at maximum achievement. For executives, incentive pay is leveraged from 100% at target to 200% at maximum. Plan design does not allow awards beyond maximum and is capped at 150% and 200% for the respective employee groups. The cost of all payments which exceed the target levels would be borne by the shareholders in this case.

Base objectives along with metrics for performance pay are products of Vectren's annual budget process that establish aggressive yet attainable business goals. The budget as well as the performance metrics are reviewed and approved by the Vectren Board of Directors, in consultation with their independent compensation consultant, Hay Group.

Q. Please describe the operational performance objectives which are part of the annual incentive plan.

A. Safety and customer service represent clear operational performance objectives. Safety in the workplace is measured by the number of OSHA recordable injuries incurred. The Vectren utility employees have had great success of reducing OSHA recordable injuries in the workplace since Vectren was formed. This objective provides an incentive to the employees to continue to achieve those good results.

Customer service is measured by three factors. They are overall customer satisfaction, customer satisfaction with specific contact points such as when customers request a new service to be added, and call center performance. Satisfaction is measured by various means, including direct customer contact and survey responses. We see clear customer benefits from our employees' great interest in customer satisfaction and safety.

Q. Please describe the financial objective of the annual performance pay plan.

A. This measure is based on achievement of Vectren earnings per share ("EPS") targets set by the Board of Directors with reference to the annual budget. As employees act upon the objective, often it is in the form of finding more efficient ways to serve the customer, such as by utilizing technology and reducing costs. The performance pay plan is an important part of the Company's efforts to control costs and maximize efficiencies, which over time have a favorable impact on customer costs.

PHASE II--REVENUE STABILIZATION CONSIDERATION

Q. Vectren North's Petition includes a second phase of this case in which the Company will propose a Revenue Stabilization mechanism. Please explain how "Phase 2" would proceed.

A. Phase 1 is the traditional base rate case being presented to the Commission. An order will determine Vectren North's revenue requirement, including its cost of capital, its rate design, and all other base rate case issues. Phase 2 would then commence with a separate procedural schedule. The new base rates would be the foundation for Vectren North's stabilization proposal. I will provide a brief description of Revenue Stabilization. If the Commission ultimately does not approve the Phase 2 proposal, there would be no impact on Phase 1, the new base rates.

Q. What is Revenue Stabilization?

A. Revenue Stabilization is a ratemaking concept that has been in existence for many years, beginning with Alabama Gas which received authorization to annually "true up" its rates to provide it with its authorized return. Since then a number of variations of this type of mechanism have been adopted by LDCs and regulators around the country. As a regulated, capital intensive business with a continual need to access the capital markets, LDCs benefit from stable financial results that will better support solid credit ratings and the ability to attract capital at a reasonable cost.

Revenue Stabilization is a general label for a concept that can take a number of forms in which the utility's annual financial results are compared to its authorized return and, within pre-determined parameters, an annual true up to the authorized return takes place.

SUMMARY

Q. Please summarize Vectren North's request in this case.

A. Vectren North is requesting a revenue increase of $41.1 million. This is a 5% overall increase. This is indicative of the fact that the investment level to serve customers has grown dramatically. While we would prefer no increase to customer rates, we believe the customer will be well served if supportive rate relief is provided that enables the Company to continue to successfully access the capital markets.

Q. Does this conclude your direct testimony?

A. Yes it does.

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

IURC CAUSE NO. 43298

DIRECT TESTIMONY
OF
M. SUSAN HARDWICK
VICE PRESIDENT, CONTROLLER AND ASSISTANT TREASURER

ON

REVENUE REQUIREMENT

SPONSORING PETITIONER'S EXHIBITS MSH-1-5

DIRECT TESTIMONY OF M. SUSAN HARDWICK

INTRODUCTION

Q. Please state your name and business address.

A. My name is M. Susan Hardwick. My business address is One Vectren Square, Evansville, Indiana 47708.

Q. By whom are you employed?

A. Vectren Corporation ("Vectren").

Q. What is your position with Indiana Gas Company, Inc., d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North" or the "Company")?

A. I am Vice President, Controller and Assistant Treasurer.

Q. What is your educational background?

A. I am a 1984 graduate of Indiana University with a Bachelor of Science Degree in Accounting. I am a Certified Public Accountant in the State of Indiana.

Q. Please describe your business experience.

A. From 1984 to 1992, I was employed by Arthur Andersen, LLP first as a staff auditor and ultimately promoted to Senior Manager. From 1992 to 1999, I was employed by PSI Energy, Inc. (PSI), and then Cinergy Corporation following the merger of PSI with The Cincinnati Gas and Electric Company, in various capacities, including Assistant Corporate Controller. Since 2000, I have served as Vice President and Controller of Vectren North and Vectren (Vectren North's ultimate parent company).

Q. What are your responsibilities as Vice President, Controller and Assistant Treasurer?

A. I am responsible for and oversee all accounting functions for Vectren North (and Vectren and its other utility subsidiaries), including financial, plant and tax accounting, budgeting, reporting and other functions.

Q. Are you familiar with the books, records, and accounting procedures of Vectren North?

A. Yes, I am.

Q. Are Vectren North's books and records maintained in accordance with the Uniform System of Accounts and generally accepted accounting principles?

A. Yes.

Q. Have you ever testified before any state regulatory commission?

A. Yes. I have testified before this Commission on behalf of Vectren North in Cause No. 42598 involving Vectren North's request for a base rate increase. I have also testified before this Commission on behalf of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") in numerous proceedings. I also testified before the Public Utilities Commission of Ohio on behalf of Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio") involving its request for a base rate increase. Vectren Corporation is also the parent company of both Vectren South and Vectren Ohio.

Q. Were your testimony and exhibits in this proceeding prepared by you or under your supervision?

A. Yes, they were.

PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual and pro forma cost of service for Vectren North and to present the components of its rate base, proposed rate of return and resulting required level of operating income. This information is presented in Petitioner's Exhibit MSH-2 and Petitioner's Exhibit MSH-3.

SUMMARY

Q. Please summarize your testimony.

A. Vectren North requires an increase in base rate revenues of $41,140,866 which will provide net operating income of $66,639,741 based on pro forma test year results.

PRO FORMA REVENUE REQUIREMENT ANALYSIS

Q. Please refer to Petitioner's Exhibit MSH-2 and explain what it represents.

A. Petitioner's Exhibit MSH-2 is a statement of operating income for the 12 months ended December 31, 2006 (the test year for this proceeding), for Vectren North shown on an actual basis, pro forma basis and adjusted for the proposed increase in revenue. Column B shows the actual results for Vectren North for the 12 months ended December 31, 2006. Column C shows the pro forma adjustments made to reflect the going level of operations in order to reflect fixed, known and measurable changes which will occur within the 12 months following the test year. Column D shows the alphanumerical designations (e.g. A01, A02, etc.) used to identify each pro forma adjustment. These pro forma adjustments are described later in my testimony. Column E shows the pro forma statement of operating income reflecting the pro forma adjustments shown in Column C. Column F shows the pro forma adjustments required to produce Vectren North's proposed revenue requirement and operating income. Column G shows alphanumerical designations identifying the adjustments reflecting the proposed rate increase. These pro forma adjustments are also described more fully later in my testimony. Column H shows the pro forma statement of operating income after adjusting for the proposed rate increase.

Q. In your opinion, does Petitioner's Exhibit MSH-2, Column E, accurately reflect Vectren North's operating results during the test year, adjusted for fixed, known and measurable changes occurring during the 12 months after the end of the test year?

A. Yes.

Q. What are the actual operating results and the effect of the pro forma adjustments shown on this exhibit?

A. The actual net operating income for the 12 months ended December 31, 2006, as shown on Column B, Line 68 of Petitioner's Exhibit MSH-2, is $58,197,419. The pro forma net operating income at present rates shown on Column E, Line 68 is $42,791,765, as adjusted for the pro forma margin and operating expense adjustments shown in Column C. These pro forma adjustments are necessary to reflect on a full twelve-month basis fixed, known and measurable changes to actual test year results.

The proposed revenue increase of $41,140,866 is required to provide an 8.43% return on net original cost rate base. This amount is shown on Column F, Line 1. The $41,140,866 revenue increase is required to produce the net operating income of $66,639,741 as shown on Column H, Line 68 page 2.

PRO FORMA ADJUSTMENTS

Q. Please describe Petitioner's Exhibit MSH-3.

A. Petitioner's Exhibit MSH-3 includes the details of each pro forma adjustment and the proposed revenue increase. This exhibit includes 50 separate attachments labeled Adjustment A01 through Adjustment A50 that describe each pro forma adjustment at present rates.

Operating Revenue and Cost of Gas

Q. Please describe Adjustments A01 through A10 shown in Petitioner's Exhibit MSH-3.

A. Adjustments A01 through A10 are pro forma adjustments to Vectren North's test year revenue and cost of gas and collectively represent a net increase in test year gas margin of $7,100,418.

Q. Please describe these adjustments in detail.

A. Adjustment A01 represents an adjustment necessary to reflect the test year margin assuming normal weather. Normal weather was determined by reference to the 30 year normal degree days as published by NOAA. The test year actual margin was negatively impacted by weather that was 551 degree days, or 10.1% on an annualized basis, warmer than normal. Though the adjustments to revenue and cost of gas are large individually, the net impact of this adjustment (revenue less cost of gas) is an increase in test year margin of $835,094, and is reflective of the actual impact during the test year of the normal temperature adjustment mechanism in place at Vectren North, which is reflected on Column C, Line 3 of Petitioner's Exhibit MSH-2.

Adjustment A02 represents an adjustment to reflect the actual year end customer count on an annualized basis. The actual customer count at December 31, 2006 of 564,438 was used to calculate an annualized margin as if that level of customers were in place throughout the year. The adjustment was determined by calculating the difference between the test year beginning and ending actual customer count and assuming that the customers represented by that difference were ratably added throughout the test year. There were 3,090 additional residential customers at December 31, 2006 as compared to December 31, 2005, and 163 additional commercial class customers for the same period; therefore, test year revenue, net of the related cost of gas, is increased by $560,973 to reflect the year end customer count impact.

Adjustment A03 represents an adjustment to miscellaneous revenue in the test year. Miscellaneous revenue includes reconnect fees, diversion, late payments (forfeited discounts), insufficient charges, and other miscellaneous revenue. The number of occurrences for the test year was not adjusted; however, the revenue per occurrence was updated to reflect revised calculations. This adjustment reflects an increase in diversion fees of $23,914, and a decrease in the forfeited discounts in the amount of $(291,813), to reflect the three year average of late payment fees as a percentage of operating revenue. In addition, other miscellaneous revenues have been reduced by $(24,000) due to the termination of a lease agreement effective January 16, 2007. The net impact of these changes is a decrease in test year revenues of $(291,899).

Adjustment A04 represents the test year margin for certain large customers that have an expected change in load requirements due to new plants, plant closures, consolidation of operations, or known billing adjustments. The adjustment reflects known changes related to twenty eight individual customers as shown on Page 2 of 2 of Adjustment A04. Three customers have commitments in place for new plants starting in 2007. The combined impact from these customers is an increase of 967,951 dekatherms, or $293,175 of revenue. Fourteen customers have either ceased operations or have notified Vectren North of expected plant closures during 2007. The customers combine to create a reduction of 1,073,414 dekatherms, or $(519,402) of revenue. Six customers are expected to have load changes due to operational impacts totaling a reduction of 282,164 dekatherms, or $(64,216) of revenue. Finally, five customers during the test year had more or less than twelve months of bills due to timing issues. This adjustment reflects these customers on an annualized basis and results in a reduction of 101,640 dekatherms, or $(6,115) of revenue. The net impact to the test year from all of these large customer changes is a reduction of $(296,558) in test year revenue. As these are all transportation customers, there is no cost of gas impact. Vectren North Witness Thomas L. Bailey supports this adjustment further in testimony, along with the overall forecast of future large customer changes for Vectren.

Adjustment A05 represents the annualized impact on test year margin of customers that have migrated between customer classes during or subsequent to the test year. The establishment of Rate 225 for School Pooling customers created a shift of 4,484 customers from Rates 220 and 240. In addition, large customer changes in usage patterns created shifts between Rates 245, 260, and 270. Net, the impact of customer migration on the test year is a decrease in test year revenue of $(38,538).

Adjustment A06 represents the removal of the change in unbilled revenue recorded in the test year of $1,000,466 as the revenues and cost of gas presented herein reflect a billed basis rather than an unbilled basis.

Adjustment A07 represents the removal of the Sales Reconciliation Component (SRC) of the Energy Efficiency Rider (EER) recorded in the test year of $(653,611). The SRC was approved December 1, 2006 pursuant to the

Commission order in Cause Nos. 42943 and 43046. This deferred amount will be recovered in the SRC of the EER effective April 1, 2007.

Adjustment A08 reflects an adjustment of $258,819 to reflect the expected level of Pipeline Safety Act costs that will be recovered during the pro forma year under the Pipeline Safety Adjustment (PSA) tracker. This amount includes the IURT impact. There is a similar adjustment (Adjustment A20) that reflects an increase in Pipeline Safety Act costs to be incurred in the test year that will be recovered through the PSA. Both entries simply "normalize" the test year amount to reflect full allowed recovery under the PSA cap.

Adjustment A09 reflects an adjustment of $3,475,324 to reflect the expected level of conservation program costs under the Energy Efficiency Funding Component (EEFC) that will be recovered during the pro forma year under the EER. This amount includes the IURT impact. Adjustment A21 reflects an increase in operating expense associated with conservation programs that will be recovered through the EEFC component of the EER. Both entries simply "normalize" the test year amount to reflect full allowed recovery under the EEFC component of the EER. This approach assumes that the existing EEFC mechanism continues as currently implemented (i.e. costs are tracked and not embedded in base rates).

Adjustment A10 represents an adjustment to reflect the current expected cost of gas per dekatherm of $9.016. The increase from the test year of $8.398 per dekatherm at the test year level of volumes results in the adjustment. This adjustment is reflected in both revenues and cost of gas, with no net impact on margin, except for the impact of the Indiana Utility Receipts Tax on the higher cost of gas and other impacts in the test year related to out of period adjustments.

Because of the volatile nature of gas costs, fixing the recovery of the cost of unaccounted for gas in base rates is not appropriate. Vectren North proposes that the actual cost of unaccounted for gas that varies from the base cost of gas established in this proceeding be recovered through the Gas Cost Adjustment ("GCA") mechanism. Vectren North Witness Scott E. Albertson discusses this proposal in more detail.

The majority of the adjustments discussed above (A01-A10) reflect both a revenue and cost of gas component. The net impact of all of these adjustments, as noted above, is an increase in test year margin of $7,100,418.

Operations and Maintenance Expense

<u>Labor and Labor Related Costs:</u>

Q. Please describe Adjustment A11 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A11 represents an adjustment to pro forma labor costs. Test year labor expense was $31,542,849 and the pro forma level is $33,370,356, which results in Adjustment A11, an increase of $1,827,507. The adjustment is calculated based on the actual number of employees (filled positions) as of December 31, 2006 and the level of wage increases, fringe benefits and payroll taxes expected to be in effect for the twelve months subsequent to the test year. This adjustment includes the annualization of a 3.0% wage increase to union employees (IBEW, USWA) effective December 4, 2006 and a 3.0% wage increase to go in effect in December 2007. The union employee wage increase is $248,494 of the total adjustment. The wage rates as of December 31, 2006 for non-union employees, escalated at 3.5%, were used in the calculation of the pro forma adjustment. The 3.5% increase is the amount of the budgeted non-union salary increase for 2007 that went into effect March 1, 2007. The portion of the adjustment attributable to non-union employee wage increases is $778,561.

The fringe benefit (healthcare, 401K, and other costs) loading rates and payroll tax rates based on 2007 budgeted costs and expected to be in effect for the twelve months subsequent to the test year were used to determine the pro forma level of benefit expenses. A cost allocation, or "loading", process is used to distribute benefit costs based on direct labor charges. The portion of the adjustment related to increased wages and benefit costs is $333,205.

The remaining portion of the adjustment, or $467,247, is attributable to changes to cost allocations and annualized wage and benefit costs of employees added during the test year.

Q. Please describe the cost allocation factors and related process in effect during the test year.

A. Cost allocation factors are used to distribute common administrative, supervision and certain other costs to the appropriate entities within Vectren Corporation. Allocation factors appropriate for each type of cost, such as number of customers, number of employees, operating margin, capital expenditures, etc., are used to derive weighted percentages that are then applied to costs incurred that are relevant to the factor. As an example, customer service costs are allocated to the various utility companies based on the number of customers served by each utility.

The methodology and development of the allocation factors used in the test year and currently in effect are reviewed by the Company's independent auditor, Deloitte & Touche, LLP ("Deloitte") as part of the annual financial statement audit process, and were found to be appropriate, reasonable and consistent with industry practice. Where applicable, these cost allocation factors have been applied in the calculation of the remaining pro forma adjustments described throughout the remainder of my testimony. The allocation percentages for the more significant allocators currently in place for Vectren North are as follows:

- For costs allocated based on number of employees, the allocation percentage for Vectren North is 35%. For example, this allocation percentage would apply to all labor-related costs as shown in Adjustment A12 discussed below.
- For costs allocated based on number of utility customers, the allocation percentage for Vectren North is 49%. For example, this allocation applies to customer credit and collection and billing costs as shown in Adjustments A27-A28 and Adjustment A30 discussed below.
- For costs allocated based on a weighting of utility margin, capital expenditures, and payroll, the allocation percentage for Vectren North is 35%.

For example, this allocation applies to certain risk insurance expense as shown in Adjustment A34 discussed below.

- For costs allocated using a weighting of total customers, total employees, and specific asset identification, the allocation percentage to Vectren North is 38%. For example, this allocation is used to allocate costs of shared assets as shown in Adjustment A39 discussed below.

Q. Please describe Adjustments A12 and A13 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustments A12 and A13 represent adjustments to reflect the proper level of compensation costs, other than direct salary, in the test year. As key elements of its total compensation program, Vectren uses a combination of base salary, long term performance pay (restricted stock and stock options) and annual (or short term) performance pay. The total compensation program is reviewed regularly by Vectren's Board of Directors in order to determine the appropriate combination and levels of such compensation elements, as well as setting performance standards and approval of payout levels. The direct salary adjustment was included in the previously described labor cost adjustment. Adjustments A12 and A13 adjust the amount of long term and short term performance pay, respectively, based on current targets.

Q. Please explain how the long term performance pay adjustment was derived.

A. Page 2 of Adjustment A12, Petitioner's Exhibit MSH-3 shows the derivation of the appropriate level of restricted stock and stock option expense that will be incurred by Vectren North based on the number of restricted shares granted effective January 1, 2007 for Executives and May 1, 2007 for other employees, with an assumed share price of $29.44, which represents 4% growth from the 2006 year end stock price. The calculated expense amount is compared to the actual amount in the test year, resulting in a difference related to restricted stock of $781,443. In the test year, Vectren North expensed $89,099 associated with employee stock options based on the Financial Accounting Standards Board (FASB) standard that was effective January 1, 2006. Vectren does not intend to issue stock options in the future and therefore this cost has been removed from Vectren North's cost of service. Combined, the adjustment to reflect the target level of long term performance pay of $1,693,733, compared to the test year level of $1,001,389, is an increase in operating cost of $692,344.

Q. Please explain the adjustment for annual (short term) performance pay shown in Adjustment A13 of <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A13 reflects the appropriate level of short term annual performance pay that will be incurred by Vectren North based on the performance plan targets that have been approved by Vectren's Board of Directors for 2007. The annual performance pay plan is based on a weighting of performance measures such as earnings, safety, and customer satisfaction. The adjustment amount of $1,101,812 is determined by comparing the calculated amount of $2,115,784, which represents targeted performance, to the amount in the test year of $1,013,972.

Q. Please describe Adjustments A14 and A15 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A14 is an adjustment to reflect the pro forma pension expense determined pursuant to FASB's Statement of Financial Accounting Standards No. 87 ("FAS 87"), and Adjustment A13 is an adjustment to reflect the expense of pro forma post retirement benefits other than pensions determined pursuant to FASB's Statement of Financial Accounting Standards No. 106 ("FAS 106") on an accrual basis. The test year amount for pension expense was $2,670,317. The pro forma decrease in pension expense is $(370,900) resulting in a pro-forma expense of $2,299,417. As shown in Adjustment A15, the test year expense for post retirement benefits other than pensions was $1,037,075. The pro forma expense is $1,162,187, resulting in a pro forma increase in post retirement expenses of $125,112. The annual level of pension and post retirement benefits expense was determined by the Company's actuary, Towers Perrin, based on actuarial calculations using current census data and actuarial assumptions, as reviewed and approved by Vectren's Investment Committee, and as reflected in the 2006 Plan Year actuarial valuations which includes costs to be recognized in

2007. The pro forma level of expense is determined consistent with FAS 87 and FAS 106 as reflected in the GAAP financial statements.

Q. Please describe Adjustment A16 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A16 represents an adjustment to additional participation in various training programs including certain refresher safety training and emergency preparedness and disaster programs for distribution operations personnel. The impact of this adjustment is to increase training costs in the amount of $388,744 and is discussed further by Vectren South Witness William S. Doty.

Q. Please describe Adjustment A17 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A17 represents an adjustment to reflect additional employees added or expected to be added since the end of the test year. The additional employees consist of 70 positions. All of the positions are approved and the majority of the positions are expected to be filled during the pro forma period. Many of the positions included are existing positions that were vacant as of the test year end and are included in this pro forma to reflect that replacements are being sought. The pro forma adjustment also includes new proposed positions to support new operational initiatives. After the appropriate allocation of costs to Vectren North, the portion of the adjustment attributable to wages for the positions totals $2,296,109. The remainder of the adjustment represents the fringe benefits and payroll taxes related to those positions. The portion of the adjustment attributable to benefit costs is $1,285,821. The total adjustment is reduced by $(43,111), which represents test year expenses associated with temporary employees performing some of the functions required on these incremental additions. In total, the pro forma adjustment is $3,538,819. The new positions proposed under the Human Resources heading of Adjustment A17, Page 2 of 2 (lines 2-8) are discussed in detail by Vectren North Witness Ellis S. Redd. The new positions proposed that are under the Economic Development and Marketing heading (lines 16-20) are discussed in detail by Vectren North Witnesses Ronald B. Keeping and Douglas A. Karl. The new operations related positions proposed (lines 22-45) are discussed in detail by Vectren North Witnesses William S. Doty, Eric J. Schach, Thomas L. Bailey, and James M.

Francis. The remaining positions are detailed on lines 10-14 of Adjustment 17, Page 2 of 2 and are shared service, or A&G, type positions for Vectren's Information Technology and Corporate Records departments. These positions are needed to support initiatives proposed in Adjustment A31 described below.

Q. Please describe Adjustment A18 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A18 represents additional expense related to Human Resource Programs such as training and development, recruiting and employment, and corporate diversity. The total impact of these programs is an increase of $183,750, and is discussed in further detail by Vectren North Witness Ellis S. Redd.

<u>Aging Workforce Related Costs:</u>

Q. Please describe Adjustment A19 shown in <u>Petitioner's Exhibit MSH-3</u>.

Adjustment A19 reflects $535,687 in additional expense on a pro forma basis that will be incurred by Vectren North related to its aging workforce. Vectren North Witness William S. Doty supports this issue in substance and addresses the adjustment as it affects operations.

<u>Operation and Maintenance Programs:</u>

Q. Please describe Adjustment A20 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A20 reflects additional costs over the test year amount that will be incurred and recovered through the PSA tracker during the pro forma period. See the related revenue entry at Adjustment A08 and the related portion of Adjustment A06. The net impact of these entries on net operating income is zero.

Q. Please describe Adjustment A21 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A21 reflects additional costs over the test year amount that will be incurred and recovered through the EEFC during the pro forma period. See the related revenue entry at Adjustment A09 and the related portion of Adjustment A06. In addition, a segment of these costs, reflected on line 8 of Adjustment A21, is captured in the depreciation adjustment discussed below in Adjustment

A41 and is removed from Adjustment A21. The net impact of these entries on net operating income is zero. This approach assumes that the existing EEFC mechanism continues as currently implemented (i.e. costs are tracked and not embedded in base rates).

Q. Please describe Adjustment A22 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A22 reflects an increase in gas storage facility maintenance expense of $343,488. This expense is needed to conduct maintenance and painting of the storage stations, tanks, and wells. In addition, programs will be put in place to monitor and assess the integrity of the gas storage wells. Vectren North Witness Eric J. Schach provides additional support for this adjustment.

Q. Please describe Adjustment A23 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A23 reflects an increase in distribution maintenance expense of $2,169,154. This includes additional expense above the test year amount for transmission and distribution right of way clearing. The adjustment also includes incremental expenses for the establishment of an aerial pipeline patrol program and the creation of an automated crew call out program. Vectren North Witness Eric J. Schach provides additional support for this adjustment.

Q. Please describe Adjustment A24 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A24 reflects an increase in regulator station maintenance expense from the test year level of $58,215 to a pro forma level of $1,311,433, an increase in expense of $1,253,218. This adjustment covers increased regulator station repairs and maintenance, along with the establishment of a 15 year cycle for sandblasting and painting. Vectren North Witness Eric J. Schach provides additional support for this adjustment.

Q. Please describe Adjustment A25 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A25 reflects an increase in expense of $1,275,212 for incremental meter set maintenance. This maintenance involves investigation and remediation of meter pressure factor errors for both residential and general service meters. Also included are additional incremental expenses in defining an annual meter set painting program that proposes to paint and service 1.5% of the meter sets each year. Adjustment A25 is discussed in further detail by Vectren North Witnesses William S. Doty and Eric J. Schach.

Q. Please describe Adjustment A26 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. The pro forma level of bad debt (uncollectible accounts) expense was determined by applying the three year average of actual write-offs experienced by Vectren North of 0.91% of revenues to pro forma revenues of $821,888,922 as calculated in Adjustment A26. The three years of actual write-off experience used were the twelve month periods ending December 31, 2004 and 2005, and the test year. Similarly, actual revenues for the same period were used in the calculation, along with pro forma revenues for the test year. This calculation resulted in a pro forma level of bad debt expense of $7,479,189 compared to the test year amount of $7,547,722, or a decrease in expense of $(68,533).

Because of the continued volatility of natural gas prices and the resulting impact on customers' ability to pay, Vectren North proposes that the gas cost component of bad debts to the extent it varies from the amount set in base rates in this proceeding be recovered through the GCA mechanism. Use of the GCA recovery mechanism serves the interests of the company in addressing costs that fluctuate from year to year largely outside of its control, and the interests of customers given that it is equally possible that this cost will decline if gas prices decline. Vectren North Witness Scott E. Albertson discusses the proposal in more detail.

Q. Please describe Adjustment A27 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A27 reflects an increase in miscellaneous billing and meter reading expense of $221,990. Of this total, $112,700 was calculated by applying the $0.02 postage increase effective May 14, 2007 to the total mail pieces sent annually, with 49% allocated to Vectren North. The remaining portion of this increase relates to additional cost for dispatching contractor crews to complete hard closes on meters in cases of customer disconnection or move, and an approximate 2% historical growth in the number of meter reads annually.

Additional support for this necessary adjustment is provided by Vectren North Witness William S. Doty.

Q. Please describe Adjustment A28 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A28 reflects Vectren North's share of the decreased outsourced contract labor for the contact center along with an adjustment to test year values. This adjustment is a reduction to expense of $(194,367). Effective March 2007, Vectren has a contract in place with its outsourced contract labor provider, IRMC, which will reduce annual costs for the contact center by $(56,786) allocated to Vectren North. The remaining amount is an adjustment to the test year expense level to reduce the total payments to IRMC from 13 in the test year to 12. Vectren North Witness William S. Doty provides additional support for this adjustment.

Q. Please describe Adjustment A29 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A29 in the amount of $719,424 represents incremental expense associated with school and customer safety communication programs. Based on results from industry surveys and focus groups, Vectren's customers desire more direct communication from the utility as it relates to safety and reliability. These programs propose to address this need by creating a safety education program to reach schools in the 55 counties served by Vectren North, and by creating defined outreach programs for customers through various media outlets. As part of Adjustment A17, Vectren also proposes to hire one additional Communications Specialist to assist in developing and administering these programs. Additional support for this adjustment is provided by Vectren North Witness William S. Doty.

Q. Please describe Adjustment A30 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A30 in the amount of $288,263 represents Vectren North's increased annual cost in the areas of economic development and marketing research. The overall intent of this additional cost is to provide strategic focus on growing economic development opportunities and in increasing customer satisfaction through more direct communication and exchange with our customer base, particularly commercial and industrial customers. Additional detailed support for this adjustment is provided in the testimony of Vectren North Witness Ronald B. Keeping.

Q. Please describe Adjustment A31 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A31 represents an adjustment of $428,724 allocated to Vectren North for various information technology contractual obligations associated with an expanding mobile workforce, estimated costs for maintenance and support of internal hardware and software, and telecommunications fees and taxes. Of the total cost, $67,770 represents contractual maintenance fee increases or expiration of warranties related to computer operations and systems integration. These items are noted on Adjustment A31, Page 2 of 2, lines 16-19.

Vectren's increasing mobile workforce has also created additional expense of $117,916 in the networking and telecommunications area as shown on lines 20-23 of Adjustment A31. In the next year, Vectren plans to deploy an additional 200 mobile devices to aid in field workforce productivity and customer service. These new units allow technicians to interface directly and quickly with support systems and customer data. This mobilization will create incremental expenses for new maintenance and support agreements, along with additional tower rental fees. In addition, the adjustment includes the removal of a one-time tax credit recorded in the test year related to a federal ruling to refund previously paid long distance fees.

The remaining portion of the adjustment totaling $243,038 and noted on lines 24-29 of Adjustment A31, covers the additional application support of many of Vectren's business processes. These include annual software support fees, new software releases, and various maintenance agreements. The total impact of all of these items as noted in Adjustment A31 is an increase in pro forma operating expenses of $428,724.

<u>Amortization of Deferrals:</u>

Q. Please describe Adjustment A32 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A32 represents an adjustment to increase test year expenses for the estimated incremental rate case costs associated with this proceeding. Line 1 of page 2 reflects the total unamortized costs from Cause No. 42598 as of December 31, 2006. This balance will be completely amortized by December 31, 2007, as noted on line 3. Line 4 represents estimated costs of the current proceeding and the sum of the total rate case costs to be amortized. Vectren North proposes a three year amortization of the rate case costs which represents the period of time since Vectren North's last base rate case. Line 6 reflects the pro forma costs amortized over the three-year period. The pro forma adjustment of $120,589 shown on Line 3 of page 1 represents the annual amortization of the estimated expenses of $308,667 less the test year amount of amortization from the prior case of $188,078.

Q. Please describe Adjustment A33 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A33 is an adjustment to reflect the amortization of the expected deferred costs incurred as of December 31, 2007 related to the requirements of the Pipeline Safety Improvement Act of 2002. In accordance with the Commission order in Cause No 42598, Vectren North has in place a recovery mechanism, the PSA tracker, for the periodic recovery of such costs. The annual recovery of such costs is capped at $2,500,000 currently, with no carrying costs. The costs incurred to date have exceeded the cap and as a result a deferred balance has accumulated. Further it is expected that the deferral will continue to grow with additional expenses in calendar year 2007. This adjustment proposes that the estimated deferred balance of $5,595,480 as of December 31, 2007 be amortized over a three year period. At the effective date of new rates, if the deferred balance differs from the pro forma amount included in base rates, it is proposed that the difference be included in the PSA tracker going forward. Because of the relative newness of this effort and the variability in the annual cost, the existing PSA tracker mechanism should remain in place. The details of the pipeline safety program are further discussed by Vectren North Witness James M. Francis. Vectren North Witness Scott E. Albertson further discusses the ongoing Pipeline Safety Adjustment approved in Cause No 42598.

Other Costs/Adjustments:

Q. Please describe Adjustment A34 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A34 is an adjustment to reflect the level of property insurance expense related to its utility property at the end of the test year. Included in the adjustment is a decrease in property insurance expense for the test year of $(27,483). The pro forma property insurance expense reflects current premiums for Vectren North insurance coverage for its gas utility property.

The adjustment also reflects the pro forma level of risk insurance expense. The pro forma risk insurance expense reflects current premiums for insurance covering workers compensation, automobile liability, and corporate liability. The pro forma adjustment resulted in a reduction in risk insurance expenses of $(87,575). Combined, the adjustment to reflect the appropriate pro forma level of property and risk insurance of $1,690,160 is a decrease in expense of $(115,058) from a test year level of $1,805,218. The decrease in expense results primarily from Vectren North's decision to address rising insurance premium costs by accepting a higher degree of self-insured risk. In late 2006 deductibles were increased from $1 million to $3 million on both the property and liability lines of coverage. The $1 million deductible had been in place for many years. With the insurance market reacting to terrorism risk and casualty losses caused by hurricanes, premium costs have risen significantly in the last several years. While this decision reduces insurance expense, risk is clearly heightened.

Q. Please describe Adjustment A35 shown in Petitioner's Exhibit MSH-3.

A. As noted above, Vectren North is self-insured for a portion of its injury and damage claims (i.e. Vectren insurance policies have a deductible of $3.0 million per occurrence). The pro forma level of claims expense of $878,498 is based on an average of actual claims paid experience over the past five years. Reflective of the increased risk of higher claims expense that comes simply from raising the deductible amount, the historical average of actual claims paid is "amortized" through this adjustment over a three year period as a reasonable attempt to quantify that increased risk. The pro forma level is compared to the test year amount of $227,856, resulting in an increase in claims expense of $650,642.

Q. Please describe Adjustment A36 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A36 reflects the reduction in test year expenses of $(427,956) related to the former Vectren North corporate headquarters in Indianapolis. Effective early in 2007, that facility is no longer under lease by the Company and was not fully utilized in the operation of the utility during the test year. The reduction in lease and operating expense was offset somewhat by the annual lease expense allocated to Vectren North for new offices in Indianapolis. Since the Vectren merger, the Company's headquarters have been maintained in Evansville.

Q. Please explain Adjustment A37 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. The purpose of an allocation factor is to allocate costs in a manner that best represents cost causation. During the annual budgeting process, cost center allocation factors and the level of administrative and general costs subject to capitalization are reviewed for appropriateness and are adjusted as needed. Adjustment A37 reduces test year expenses by $(110,784) for costs in cost centers for which the allocation factor changed during the 2007 budget process and to reflect increased capital costs.

Also in analyzing test year operating costs, it was determined that $14,136 of costs in outside services and certain other expenses were charged in error to other Vectren entities instead of Vectren North. Adjustment A37 adds this amount to Vectren North's operating expenses. The sum of these items represents a decrease in test year expenses of $(96,648).

Q. Please describe Adjustment A38 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A38 reflects the pro forma level of Indiana Utility Regulatory Commission (IURC) Fees and is determined by applying a rate of 0.11% to the pro forma level of revenues for the test year. The pro forma revenue includes pro forma margins shown on <u>Petitioner's Exhibit MSH-2</u> plus pro forma gas costs. The pro forma increase of $119,803 was calculated as the difference between the pro forma level of IURC fees and the test year amount.

Q. Please describe Adjustment A39 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A39 reflects a pro forma increase in Vectren Utility Holdings' (VUHI) (a Vectren subsidiary) asset charges for the test year. VUHI owns certain information technology assets and buildings and charges each of the Vectren utility and non-utility operations, including Vectren North, for amounts reflecting their respective use of those assets. The asset charge covers the carrying costs on property and equipment recorded on VUHI's books. The asset charge includes depreciation expense, property taxes, and a fair and reasonable return on net plant. Line 1 of page 1 of Adjustment A39 shows the gross plant for VUHI at December 31, 2006. Line 3 shows the net plant determined by subtracting accumulated depreciation from gross plant. The return and income taxes shown on Line 5 is calculated by applying the Vectren North cost of capital (as calculated in this proceeding) grossed up for income taxes to the net plant shown on Line 3. The calculation of the weighted cost of capital grossed up for income taxes is shown on Page 2 of Adjustment A39. Depreciation expense of $21,450,829 is shown on Line 6 of Adjustment A39 and represents annualized depreciation expense on the assets as of December 31, 2006. Property tax expense of $1,211,604 is shown on Line 7 and represents annualized property tax expense on the assets as of December 31, 2006. The pro forma asset charge attributable to Vectren North operations is $15,620,049. The pro forma adjustment results in an increase of $478,466 that is shown on Line 12 of page 1 and is determined by calculating the difference between the pro forma level of asset charges attributable to Vectren North operations and the amount reflected in the test year.

Q. How are these asset costs charged to Vectren's various entities?

A. The three largest assets shared among Vectren's operating entities are its customer billing system, call center, and corporate headquarters. The costs allocated to each entity have been calculated independently for these assets. Costs for the customer billing system and the call center are allocated only to the utilities using a blended rate of utility customers and utility full time equivalent employees. The corporate headquarters is allocated between regulated utilities and non-regulated operations using square footage. The utility-related costs are then allocated to each of the operating utilities using a blended rate of each utility's customers and each utility's employees. The costs associated with all of VUHI's other assets are allocated to both utility and non-regulated operations using a blended rate, weighted equally for total customers and employees.

Q. Why is the charge for the use of these assets shown as a separate component in the determination of Vectren North's net operating income?

A. The assets owned by VUHI are shared among Vectren's operations and are used predominantly by the utility operations. Because the functions performed by these assets are common to the utilities (i.e. customer billing systems, financial systems, buildings, etc.), it is more efficient to have them centrally owned and operated. Without this sharing, each utility company would own its own such assets and include the costs in its rate base with a fair return thereon required. The centralized ownership certainly provides the opportunity for economies of scale. The amounts charged to each utility mirror the treatment that would be achieved if the assets were in rate base by charging a return of and on the investment, as well as operating costs like property taxes. The amount charged is shown on the financial statements as an operating expense, akin to a lease or rental charge.

<u>Depreciation Expense, Taxes Other than Income, and Income Taxes:</u>

Q. Please describe Adjustment A40 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A40 reflects the pro forma adjustment to depreciation expense. The pro forma level of depreciation expense shown on Line 1 of $50,435,116 is based on utility plant balances as of December 31, 2006 by primary account plus estimated additional distribution expenses associated with the Greencastle and Greensburg projects to be completed during the pro forma period and the applicable depreciation rates currently in effect and in effect since the last Vectren North gas base rate proceeding. The pro forma increase in depreciation expense of $1,977,581 from a test year level of $48,457,535 is shown on line 3. A depreciation study was not performed in this case as the current rates are believed to be appropriate as there have been no significant additions or retirement of assets, no significant changes in the operation of the assets, or the expected lives of assets in service since the prior study.

Q. Please describe Adjustments A41, A42, and A43 that are shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustments A41 and A42 show the pro forma state and Federal income tax expense reflecting all pro forma adjustments shown on Column C of <u>Petitioner's Exhibit MSH-2</u>. These calculations also reflect synchronized interest of $21,976,095 as calculated on page 3 of Adjustment A45.

These pro forma entries result in a combined Federal and state effective tax rate of 40.3%.

Adjustment A43 shows the pro forma increase in Utility Receipts Tax. The adjustment reflects the Utility Receipts Tax of 1.4%.

Q. Please describe Adjustment A44 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A44 is an adjustment to reflect the pro forma level of property tax expense related to Vectren North property. The pro forma level was determined by multiplying the 2006 taxes paid by the three year average annual increase in property tax rates and assessed value. The 2006 taxes paid were adjusted on Line 2 of Page 2 to remove the portion related to the former corporate headquarters building addressed in Adjustment A36. The pro forma adjustment is an increase in expense of $551,763, which is the difference between the pro forma level of $10,117,719 and the test year amount of $9,565,956.

<u>PROPOSED REVENUE INCREASE</u>

Q. Please describe Adjustment A45 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A45 shows the calculation of the increased revenue requirement for Vectren North necessary to provide an 8.43% return on net original cost rate base of $790,507,009. The 8.43% rate of return on page 3 of Adjustment A45 is supported in the testimony of Vectren North Witness Robert L. Goocher. The increased revenue requirement is calculated by determining the required increase in operating income. The required operating income is determined by applying the proposed rate of return of 8.43% to the net original cost rate base for Vectren North shown on page 2 of Adjustment A45. The increase in operating income is then grossed up for the following taxes and fees: (a) Federal income taxes, (b) State income taxes, (c) Utility Receipts taxes, and (d) IURC Fees. The total proposed increase in revenue requirements to provide an 8.43% return on net original cost rate base is $41,140,866.

Q. How was the original cost rate base determined, as shown on page 2 of 3 of Adjustment A45 shown in <u>Petitioner's Exhibit MSH-3</u>?

A. The original cost rate base of $790,507,009 shown on page 2 of 3 of Adjustment A41 represents the plant in service balance per the Company's books and records as of December 31, 2006 less the accumulated depreciation reserve as of the same date plus the thirteen month average of the book balances of materials and supplies, stores expense, and gas in underground storage. The total rate base includes estimated transmission additions in Greencastle and estimated upgrades in Greensburg to support the new Honda production facility that are expected to go in service during the pro forma period. Vectren North Witnesses James M. Francis and Thomas L. Bailey discuss in further detail each of these projects.

Q. Please describe Adjustment A46 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A46 reflects the additional uncollectible accounts expense on the revenue increase requested using the three year average actual write-offs as a percentage of revenue, for an increase in expense of $374,382 at the proposed rates level.

Q. Please describe Adjustment A47 shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustment A47 reflects the IURC fee on the requested revenue increase at .11%, or $45,255.

Q. Please describe Adjustments A48, A49, and A50 that are shown in <u>Petitioner's Exhibit MSH-3</u>.

A. Adjustments A48 and A49 are calculations of the income taxes applicable to the proposed increase in revenue requirements for Vectren North operations, and are calculated by applying the 35.0% federal income tax rate and the 8.5% state income tax rate to the proposed increase. Although the impact reflects only the incremental tax effects, the calculation is performed showing a complete state and federal income tax calculation.

Adjustment A50 is a calculation of the Indiana Utility Receipts Tax applicable to the proposed increase in revenue requirements for Vectren North operations and is calculated by applying the 1.4% rate to the proposed increase.

Q. Please describe <u>Petitioner's Exhibit MSH-4</u>.

A. Petitioner's Exhibit MSH-4 is a summary by FERC account that reflects the posting of the pro forma adjustments discussed above by account. This was prepared to aid in the review of the entries and their impact on each account.

Q. Please describe <u>Petitioner's Exhibit MSH-5</u>.

A. This exhibit contains Vectren North's Comparative Financial Statements for the periods ended December 31, 2006 and 2005, as required by the Commission's Minimum Standard Filing Requirements.

<u>SUMMARY</u>

Q. Please summarize your testimony.

A. As shown in Column F of <u>Petitioner's Exhibit MSH-2</u>, Vectren North is proposing an increase in revenue of $41,140,866, which will provide a net operating income of $66,639,741 based on pro forma results for the test year. This net operating income produces a return on original cost rate base of 8.43%.

Q. Does this conclude your testimony?

A. Yes.

VECTREN NORTH
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
	Operating Revenues							
1	Gas Revenue	$ 739,160,641			$ 821,888,922	41,140,866	A45	863,029,788
2	Normal Weather		$ 55,010,353	A01				
3	Normal Temperature Adjustment Revenue		$ (8,715,823)	A01				
4	Customer Count		$ 2,041,158	A02				
5	Miscellaneous Revenue		$ (291,899)	A03				
6	Large Customer Changes		$ (296,558)	A04				
7	Customer Migration		$ (38,538)	A05				
8	Unbilled Revenue		$ 1,000,466	A06				
9	Sales Reconciliation Rider Revenue		$ (653,611)	A07				
10	Pipeline Safety Act Cost Recoveries		$ 258,819	A08				
11	Energy Efficiency Funding Recoveries		$ 3,475,324	A09				
12	Cost of Gas		$ 30,938,590	A10				
13								
14	Total	$ 739,160,641	$ 82,728,281		$ 821,888,922	41,140,866		863,029,788
15	**Cost of Gas**	503,024,519			$ 578,652,382			578,652,382
16	Normal Weather		$ 45,459,436	A01				
17	Customer Count		$ 1,480,185	A02				
18	Cost of Gas		$ 28,688,242	A10				
19								
20		503,024,519	75,627,863		578,652,382	-		578,652,382
21	Gross Margin	$ 236,136,122	$ 7,100,418		$ 243,236,540	$ 41,140,866		$ 284,377,406
	Operation and Maintenance Expenses							
22	Operations and Maintenance Expenses	$ 79,121,734			$ 98,942,811			99,362,448
23	**Labor and Labor Related Costs**							
24	Labor Adjustments for Existing Headcount		$ 1,827,507	A11				
25	Labor-Related Costs		$ 692,344	A12				
26	Other Compensation		$ 1,101,812	A13				
27	Pension Expense		$ (370,900)	A14				
28	Postretirement Medical Expense		$ 125,112	A15				
29	Training Expense		$ 388,744	A16				
30	Additional Employees		$ 3,538,819	A17				
31	Human Resource Programs		$ 183,750	A18				
32	**Aging Workforce Related Costs**							
33	Aging Workforce		$ 535,687	A19				
34	**Operation and Maintenance Programs**							
35	Pipeline Safety Act Costs		$ 189,719	A20				
36	Energy Efficiency Funding Costs		$ 3,055,378	A21				
37	Gas Storage Facilities Maintenance Expense		$ 343,488	A22				
38	Distribution Maintenance Expense		$ 2,169,154	A23				
39	Regulator Station Maintenance Expense		$ 1,253,218	A24				
40	Meter Maintenance Expense		$ 1,275,212	A25				
41	Uncollectible Accounts Expense		$ (68,533)	A26				
42	Miscellaneous Billing Expense		$ 221,990	A27				
43	Contact Center Expense		$ (194,367)	A28				
44	Safety Communication Expense		$ 719,424	A29				
45	Economic Development Expense		$ 288,263	A30				
46	Information Technology Expense		$ 428,724	A31				
47	**Amortization of Deferrals**							
48	Rate Case Expense		$ 120,589	A32				
49	Pipeline Safety Act Costs Amortization		$ 1,865,160	A33				
50	**Other Costs/Adjustments**							
51	Property and Risk Insurance Expense		$ (115,058)	A34				
52	Claims Expense		$ 650,642	A35				
53	Other Cost Reductions		$ (427,956)	A36				
54	Changes in Cost Allocations		$ (96,648)	A37				
55	Pro Forma Level Uncollectible Accounts					374,382	A46	
56	IURC Fee		$ 119,803	A38		45,255	A47	
57								
58		$ 79,121,734	$ 19,821,077		$ 98,942,811	419,637		99,362,448
59	Asset Charge	15,141,583	$ 478,466	A39	$ 15,620,049			15,620,049
60	Total Operations and Maintenance	$ 94,263,317	$ 20,299,543		$ 114,562,860	$ 419,637		$ 114,982,497

VECTREN NORTH
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Line No.	Description		Actual Per Books		Pro Forma Adjustments Increases (Decreases)	Ref		Pro Forma Results Based on Current Rates		Pro Forma Adjustments Increases (Decreases)	Ref		Pro Forma Results Based on Proposed Rates
	A		B		C	D		E		F	G		H
61	Depreciation and Amortization	$	48,457,535	$	1,977,581	A40	$	50,435,116					50,435,116
	Taxes												
62	Income Taxes (Federal and State)	$	14,941,723	$	(191,255)	A41	$	13,927,358		3,461,304	A48		30,229,880
63				$	(823,110)	A42				12,841,218	A49		
64	Other Taxes (IURT and Property Tax)		20,276,128	$	691,550	A43	$	21,519,441		570,731	A50		22,090,172
65			-	$	551,763	A44							
66	Total Taxes	$	35,217,851	$	228,948		$	35,446,799		16,873,253			52,320,052
67	Total Operating Expenses	$	177,938,703	$	22,506,072		$	200,444,775	$	17,292,890		$	217,737,665
68	Net Operating Income	$	58,197,419	$	(15,405,654)		$	42,791,765		23,847,976			66,639,741

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Normal Weather

Line No.	Category		
1	Revenue	$	55,010,353
2	Less: Cost of Gas		45,459,436
3	Pro forma Margin Adjustment to Reflect Normal Temperature before impact of NTA	$	9,550,917
4	Less: Normal Temperature Adjustment (NTA) recorded in test year		8,715,823
5	Net Pro Forma Margin Adjustment to Reflect Normal Temperature	$	835,094

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Normal Weather Pro Forma Adjustment

		A	B	C = B*6	D = A-C	E	F = D/E	G	H = G-E	I = H*F	J	K = I*J	L	M = I*L	N = (M/.9847)-M	O = K+M+N
		Total Therms	Non-Temp Sales & Trans. (Jul - Aug)	Non-Temp Sales & Trans. Full Year	Temp Sensitive Sales & Trans.	Actual Degree Days	Therms per Degree Day	Normal Degree Days	Departure From Normal	Normal Temp \djustment (Therm:	Net Margin Per Therm Sold	Net Margin Adjustment	Cost of Gas Per Therm Sold	Gas Cost Adjustment	IURT Gas Cost Revenue	Total Revenue
1	**Rate 210**	403,465,245	14,544,059	87,264,354	316,200,891	4,894	64,614	5,445	551	35,632,575	$ 0.1856	$ 6,612,782	$ 0.9016	$ 32,126,330	$ 499,170	$ 39,238,282
2	**Rate 220**	179,948,989	9,148,627	54,891,759	125,057,230	4,894	25,555	5,445	551	14,092,658	$ 0.1554	$ 2,189,784	$ 0.9016	$ 12,705,940	$ 197,421	$ 15,093,145
3	**Rate 240**	9,153,667	496,805	2,980,832	6,172,835	4,894	1,261	5,445	551	695,615	$ 0.0604	$ 42,015	$ 0.9016	$ 627,166	$ 9,745	$ 678,926
4	**Total**	592,567,901	24,189,491	145,136,945	447,430,956					**50,420,848**		**$ 8,844,581**		**$ 45,459,436**	**$ 706,336**	**$ 55,010,353**
5							**Billed NTA Revenue**			-		**$ 8,715,823**		-		
6							**Total Temperature Adjustment**			**50,420,848**		**$ 128,758**		**$ 45,459,436**		
7											R210	$ 6,342,112				
8											R220	$ 2,356,812				
9											R225	$ 16,899				
10											R240	$ -				
11											Total	$ 8,715,823				

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Customer Count

Line No.	Category	
1	Revenue	$ 2,041,158
2	Less: Fuel Cost	1,480,185
3	Pro Forma Margin Adjustment to Reflect Customer Count	$ 560,973

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Customer Count Pro Forma Adjustment

Line No.		Rate 210		Rate 220			
1	Customers 12/31/06	515,016		49,422			
2	Customers 12/31/05	511,926		49,259			
3	Customer Growth		3,090		163		
4	Customers 12/31/06	515,016		49,422			
5	Customers 12/31/05	511,926		49,259			
6	Average Number of Customers		513,471		49,341		
7	Percent Customer Growth		0.60%		0.33%		
8	Therms		439,097,820		194,041,647		
9	Annual Therms		2,642,432		641,031		
10	To reflect additions throughout the year		50%		50%		
11	Incremental volumes		1,321,216		320,515		
12	Volumetric margin per unit		$ 0.1963		$ 0.1630		
13	Volumetric margin		$ 259,352		$ 52,255		
14	Group I, II and III spread			72%	23%	5%	
15	Customer Growth		3,090	118	37	8	
16	Months in a year		12	12	12	12	
17	Additional Bills		37,080	1,416	444	96	
18	To reflect additions throughout the year		50%	50%	50%	50%	
19	Estimated number of bills		18,540	708	228	48	
20	Service Charge per month		$ 11.00	$ 15.00	$ 36.00	$ 75.00	
21	Service Charge Revenue per month		$ 203,940	$ 10,620	$ 8,208	$ 3,600	
22	Margin (13 + 21)		$ 463,292		$ 74,683		$ 537,974
23	Pro Forma Cost of Gas		$ 0.9016		$ 0.9016		
24	Cost of Gas (11 * 23)		$ 1,191,208		$ 288,977		$ 1,480,185
	IURT on Gas Costs						$ 22,999
	Revenue						$ 2,041,158

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Miscellaneous Revenue

Line No.	Category	
1	Pro Forma Margin Adjustment to Reflect Miscellaneous Revenue	$ (291,899)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Miscellaneous Revenue

	Miscellaneous Revenue	Test Year	Proforma	Adjustment
1	Reconnect fees	$ 1,692,516	$ 1,692,516	$ -
2	Diversion Fees	40,536	64,450	23,914
3	Late Payment Charges (Forfeited discounts)	6,040,532	5,748,719	(291,813)
4	Non-sufficient Funds Fees	222,088	222,088	-
5	Other - MBO and Misc. (Lease)	1,081,408	1,057,408	(24,000)
6	Total Miscellaneous Revenue	$ 9,077,080	$ 8,785,181	$ (291,899)

		Reconnect Fees	Diversion Fees	Insufficient Funds Charge
7	Pro Forma Fees and Charges	$ 60	$ 70	$ 25
8	Test Year Fees and Charges	$ 60	$ 44	$ 25
9	Test Year Occurrences	1,889	920	8,884
10	Proforma Amounts	$ -	$ 23,914	$ -

		Late Payment Charges
11	Proforma Revenues	$ 822,180,821
12	Late Payment Percentage	0.70%
13	Proforma Late Payment Charges	$ 5,748,719
14	Test Year Late Payment Charges	$ 6,040,532
15	Proforma Amounts	$ (291,813)

16 Lease terminating 1/16/07 - Lease payment $2,000 per month $ (24,000)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Large Customer Changes

Line No.	Category		
1	Pro Forma Revenue	$	1,176,805
2	Less: Test Year Revenue		1,473,363
3	Pro Forma Revenue Adjustment to Reflect Large Customer Changes	$	(296,558)

Adjustment to Reflect Large Customer Revenues

Rate 245	Reason	2006 Load	2006 Revenue	Adj Load	Adj Revenue	Pro Forma Load	Pro Forma Revenue
	Increasing 2007 load - expansion	19,118	$ 18,913	19,174	$ 18,943	56	$ 30
	Plant Closed - Aug 2005	-	$ 1,750	-	$ -	-	$ (1,750)
	Operations ended Jan 2007	3,945	$ 6,954	-	$ -	(3,945)	$ (6,954)
	Plant Closed - Jul 2006	16,874	$ 16,002	-	$ -	(16,874)	$ (16,002)
	Plant Closed - Mar 2006	5,780	$ 5,598	-	$ -	(5,780)	$ (5,598)
	Plant Closing - Spring 2007	3,433	$ 5,113	-	$ -	(3,433)	$ (5,113)
	Operations ended July 2006	8,860	$ 10,288	-	$ -	(8,860)	$ (10,288)
	New Plant - Feb 2006	32,826	$ 29,345	37,361	$ 33,188	4,535	$ 3,843
	New Owner	-	$ -	39,744	$ 34,995	39,744	$ 34,995
		90,836	$ 93,963	96,279	$ 87,126	5,443	$ (6,837)

Rate 260	Reason	2006 Load	2006 Revenue	Adj Load	Adj Revenue	Pro Forma Load	Pro Forma Revenue
	Plant Closed - Apr 2006	137,701	$ 63,264	-	$ -	(137,701)	$ (63,264)
	New Owner	39,808	$ 33,634	-	$ -	(39,808)	$ (33,634)
	Plant Closed - May 2006	109,110	$ 61,952	-	$ -	(109,110)	$ (61,952)
	Plant Closed - May 2006	128,931	$ 71,649	-	$ -	(128,931)	$ (71,649)
	Plant Closing - March 2007	270,802	$ 135,042	-	$ -	(270,802)	$ (135,042)
	Plant Closing - End of 2007	305,853	$ 149,933	168,640	$ 91,584	(137,213)	$ (58,349)
	Plant Closed - Feb 2006	5,133	$ 10,628	-	$ -	(5,133)	$ (10,628)
	New Plant - 2Q 2007	-	$ -	163,416	$ 89,332	163,416	$ 89,332
	Increase in 2007	70,536	$ 48,841	133,891	$ 76,607	63,355	$ 27,766
	Reduction - 13 Bills in test year	109,110	$ 61,952	90,946	$ 52,547	(18,164)	$ (9,405)
	Reduction - 13 Bills in test year	79,368	$ 54,674	74,441	$ 50,984	(4,927)	$ (3,690)
	Reduction - 13 Bills in test year	60,489	$ 45,456	54,285	$ 41,207	(6,204)	$ (4,249)
		1,316,841	$ 737,025	685,619	$ 402,261	(631,222)	$ (334,764)

Rate 270	Reason	2006 Load	2006 Revenue	Adj Load	Adj Revenue	Pro Forma Load	Pro Forma Revenue
	Plant Closed - Feb 2006	3,297	$ 4,429	-	$ -	(3,297)	$ (4,429)
	Plant Closed - Jan 2007	242,335	$ 68,384	-	$ -	(242,335)	$ (68,384)
	New Melter, Shutdown old furnace	943,472	$ 269,141	931,256	$ 265,758	(12,216)	$ (3,383)
	Indirect bypass electric furnaces	533,295	$ 155,690	200,000	$ 65,700	(333,295)	$ (89,990)
	Increase - 11 Bills in test year	343,367	$ 127,470	379,933	$ 140,877	36,566	$ 13,407
	Reduction - 13 Bills in test year	863,036	$ 17,261	754,125	$ 15,083	(108,911)	$ (2,178)
	New Plant - 2008	-	$ -	800,000	$ 200,000	800,000	$ 200,000
		2,928,802	$ 642,375	3,065,314	$ 687,418	136,512	$ 45,043
Total Large Customer Adjustment		**4,336,479**	**$ 1,473,363**	**3,847,212**	**$ 1,176,805**	**(489,267)**	**$ (296,558)**

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Customer Migration

Line No.	Category	
1	Pro Forma Margin Adjustment to Reflect Customer Migration	$ (38,538)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Remove Test Year Unbilled Revenue

Line No.	Category	
1	Adjustment to Remove the Change in Test Year Unbilled Revenue	$ 1,000,466

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Remove Sales Reconciliation Rider Revenue

Line No.	Category	
1	Pro Forma Sales Reconciliation Rider Revenue	$ -
2	Less: Test Year Sales Reconciliation Rider Revenue	653,611
3	Pro Forma Decrease in Sales Reconciliation Rider Revenue	$ (653,611)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pipeline Safety Act Cost Recoveries

Line No.	Category		
1	Pro Forma Pipeline Safety Act Cost Recoveries	$	896,964
2	Less: Test Year Pipeline Safety Act Cost Recoveries		638,145
3	Pro Forma Increase in Pipeline Safety Act Recoveries	$	258,819

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Energy Efficiency Funding Recoveries

Line No.	Category		
1	Pro Forma Energy Efficiency Funding Component Rider Recoveries	$	3,647,933
2	Less: Test Year Energy Efficiency Funding Component Rider Recoveries		172,609
3	Pro Forma Increase in Energy Efficiency Funding Component Rider Recoveries	$	3,475,324

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Cost of Gas at Present Rates

Line No.	Category		
1	Adjustment to Revenue to Reflect Pro Forma Present Rate Revenue		$ 30,938,590
2	Adjustment to Expenses to Reflect Pro Forma Cost of Gas		28,688,242
3	Pro Forma Margin Adjustments Attributable to:		
4	Decrease in Unaccounted for Gas Costs	1,776,988	
5	Increase in IURT on Cost of Gas	473,360	
6	Pro Forma Margin Adjustment to Reflect Pro Forma Cost of Gas		$ 2,250,348

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Labor Costs for Existing Headcount

Line No.	Category		
1	Pro Forma Labor Costs	$	33,370,356
2	Less: Test Year Labor Costs	$	31,542,849
3	Pro Forma Increase in Labor Costs for Existing Headcount	$	1,827,507

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Labor Costs Pro Forma Adjustment

Line No.		Direct Labor	Fringe Load 4/	Payroll Taxes 5/	Total
	Test Year:				
1	VVC allocated to Vectren North 1/	$ 3,778,229	$ 1,277,041	$ 302,258	$ 5,357,528
2	VUHI allocated to Vectren North 2/	7,792,815	2,633,971	623,425	11,050,211
3	Vectren North 3/	10,673,561	3,607,664	853,885	15,135,110
4		$ 22,244,604	$ 7,518,676	$ 1,779,568	$ 31,542,849
	Pro Forma Annualized:	Direct Labor	Fringe Load	Payroll Taxes	Total
5	VVC allocated to Vectren North	$ 3,939,587	$ 1,311,882	$ 315,167	$ 5,566,636
6	VUHI allocated to Vectren North	8,253,354	2,748,367	660,268	11,661,989
7	Vectren North	11,423,730	3,804,102	913,898	16,141,731
8		$ 23,616,671	$ 7,864,351	$ 1,889,334	$ 33,370,356
	Pro Forma Adjustment:	Direct Labor	Fringe Load	Payroll Taxes	Total
9	VVC allocated to Vectren North - Gas	$ 161,358	$ 34,841	$ 12,909	$ 209,108
10	VUHI allocated to Vectren North - Gas	460,539	114,396	36,843	611,778
11	Vectren North - Gas	750,169	196,438	60,013	1,006,621
12		$ 1,372,066	$ 345,675	$ 109,765	$ 1,827,507

1/ VVC allocated to Vectren North is representative of shared services such as Accounting, IT, Legal, HR, etc.
2/ VUHI allocated to Vectren North is representative of utility shared services such as engineering, customer services
3/ Certain cost centers costs are allocated to gas such as fleet garage, and operations offices.
4/ The Fringe Load numbers include the costs of medical plans, dental plans, non-productive labor and misc health plans at rate of 33.8% for the test year 2006, and 33.3% (2007 Budget) for the current level.
5/ Payroll Tax loading rate associated with the Vectren North labor dollars allocated was 8.0% for the test year 2006, and 8.0% for the current level.

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Restricted Stock and Stock Option Expense
(Labor-Related Costs)

Line No.	Category		
1	Pro Forma Restricted Stock and Stock Option Expense	$	1,693,733
2	Less: Test Year Restricted Stock and Stock Option Expense	$	1,001,389
3	Pro Forma Increase in Restricted Stock and Stock Option Expense	$	692,344

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Restricted Stock and Stock Option Expense Pro Forma Adjustment

Line No.		Total	Restricted Stock	Restricted Stock Dividends	Stock Options
1	Total Test Year Vectren Expense	$ 2,759,334	$ 2,062,831	$ 450,992	$ 245,512
2	Percent of Total Expense Allocated to Vectren North	36%			
3	**Total Vectren North Test Year Expense**	**$ 1,001,389**			
4	Total Vectren Expense per 2007 Projected Expense	$ 4,791,175	$ 4,209,636	$ 581,539	$ -
5	Percent of Total Pro Forma Expense Allocated to Vectren North	35%			
6	**Pro Forma Expense Allocated to Vectren North**	**$ 1,693,733**			

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Annual Incentive Compensation Expense
(Other Compensation)

Line No.	Category	
1	Pro Forma Annual Incentive Compensation Expense	$ 2,115,784
2	Less: Test Year Annual Incentive Compensation Expense	1,013,972
3	Pro Forma Increase in Annual Incentive Compensation Expense	$ 1,101,812

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Pension Expenses

Line No.	Category		
1	Pro Forma Pension Expenses	$	2,299,417
2	Less: Test Year Pension Expenses		2,670,317
3	Pro Forma Increase in Pension Expenses	$	(370,900)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Pension Expense Pro Forma Adjustment

Line No.			
1	**Actual Expense for Test Year**		
2	Total Vectren Pension Cost in Test Period	$	10,745,742
3	Percent of Total Cost Allocated to Expense		71.00%
4	Percent of Total Expense Allocated to Vectren North		35.00%
5	**Total Vectren North Expense for Test Period**	**$**	**2,670,317**
6	**Calculation of Pro Forma Expense**		
7	Total 2007 Budget for Vectren Pension Cost	$	9,385,376
8	Percent of Total Pro Forma Cost Allocated to Expense		70.00%
9	Percent of Total Pro Forma Expense Allocated to Vectren North		35.00%
10	Pro Forma Expense Allocated to Vectren North	**$**	**2,299,417**

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Postretirement Medical Expenses

Line No.	Category	
1	Pro Forma Postretirement Medical Expenses	$ 1,162,187
2	Less: Test Year Postretirement Medical Expenses	1,037,075
3	Pro Forma Increase in Postretirement Medical Expenses	$ 125,112

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Postretirement Medical Expenses Pro Forma Adjustment

Line No.			
1	**Actual Expense for Test Year**		
2	Total Test Year Vectren Cost	$	4,173,341
3	Percent of Total Cost Allocated to Expense		71.00%
4	Percent of Total Expense Allocated to Vectren North		35.00%
5	**Total Vectren North Expense for Test Year**	**$**	**1,037,075**
6	**Calculation of Pro Forma Expense**		
7	Total Vectren Expense Net of Asset Return per 2007 Budget	$	4,213,603
8	Asset Return Specific to Vectren North		530,017
9	Gross Pro Forma Vectren Cost	$	4,743,620
10	Percent of Total Pro Forma Cost Allocated to Expense		70.00%
11	Percent of Total Pro Forma Expense Allocated to Vectren North		35.00%
12	**Pro Forma Expense to Vectren North**	**$**	**1,162,187**

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Training Expense

Line No.	Category		
1	Pro Forma Increase to Reflect Training Expense	$	388,744

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Incremental Employee Expenses

Line No.	Category		
1	Pro Forma Pro Forma Incremental Employee Expenses (Page 3 of 3)	$	3,581,930
2	Less: Test Year Pro Forma Incremental Employee Expenses	$	(43,111)
3	Pro Forma Increase in Incremental Employee Expenses	$	3,538,819

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Pro Forma Miscellaneous Employee Expenses

Line No.	Incremental Positions to Vectren	Total Vectren Labor	Total Vectren Labor Related Costs	Total Vectren Total	Allocated to Vectren North Labor	Allocated to Vectren North Labor Related Costs	Allocated to Vectren North Total
1	**Human Resources**						
2	Recruiting and Employment Specialist - support recruiting and hiring efforts	$ 31,730	$ 17,769	$ 49,499	$ 11,106	$ 6,219	$ 17,325
3	Training Specialist - create and faciliate training programs	31,767	17,790	49,557	11,118	6,226	17,345
4	Financial Analyst - invoice processing and financial transaction accuracy	45,700	25,592	71,292	15,995	8,957	24,952
5	Retirement Plan Administrator - administer pension and defined contribution programs	58,200	32,592	90,792	20,370	11,407	31,777
6	HR Generalist - general employment policy and support organizational transformations	59,300	33,208	92,508	20,755	11,623	32,378
7	Productivity Analysts (2 FTE's) - continued development of continuous improvement program	130,000	72,800	202,800	39,000	21,840	60,840
8	Employee Relations Director - oversight of labor contracts and employment issues	131,000	73,360	204,360	45,850	25,676	71,526
9	**Information Technology and Corporate Records**						
10	Network Telecommunication Analyst - network communication support	72,000	40,320	112,320	25,200	14,112	39,312
11	Applications Analyst (2 FTE's) - software maintenance	120,000	67,200	187,200	42,000	23,520	65,520
12	Database Administrator II - database design and support	68,500	38,360	106,860	23,975	13,426	37,401
13	Service Desk Specialist II - network and software support	43,200	24,192	67,392	15,120	8,467	23,587
14	Corporate Records Clerk - administration of corporate records	30,000	16,800	46,800	11,100	6,216	17,316
15	**Economic Development and Marketing**						
16	Economic Development Representative - timely reponse to customer feedback	47,000	26,320	73,320	23,030	12,897	35,927
17	Market Research Analyst-timely response to customer feedback	64,000	35,840	99,840	31,360	17,562	48,922
18	Conservation Analyst - identify and implement conservation initiatives	64,000	35,840	99,840	31,360	17,562	48,922
19	Economic Development Manager - support Vectren North economic development activities	80,000	44,800	124,800	39,200	21,952	61,152
20	Director of Marketing Services - timely reponse to customer feedback	131,000	73,360	204,360	64,190	35,946	100,136
21	**Operations**						
22	Financial Analysts - financial transaction accuracy	58,000	32,480	90,480	28,420	15,915	44,335
23	Safety/Industrial Hygiene Consultant - regulatory safety compliance and conduct safety training	80,130	44,873	125,003	39,264	21,988	61,251
24	Safety and Training Employee Relations Consultant - monitor regulatory compliance of safety training	82,900	46,424	129,324	40,621	22,748	63,369
25	Contract Administration Manager and Clerk (2 FTE's) - requirement for legal, regulatory and SOX compliance	118,750	66,500	185,250	41,563	23,275	64,838
26	Buyer - procurement activities	55,000	30,800	85,800	19,250	10,780	30,030
27	Contracts Analyst - contractual review	15,000	8,400	23,400	7,350	4,116	11,466
28	Engineer (7 FTE's) - compliance with DOT and company standards	382,016	213,929	595,945	194,993	109,196	304,189
29	Program/Project Manager - manage assigned special projects	12,400	6,944	19,344	4,340	2,430	6,770
30	Gas Dispatcher (2 FTE's) - system reliability	64,758	36,264	101,022	36,912	20,671	57,583
31	Dispatch Manager - oversight of gas dispatch	83,200	46,592	129,792	47,424	26,557	73,981
32	Corrosion Control Specialist - manage corrosion protection system and remediation	56,784	31,799	88,583	38,045	21,305	59,351
33	Field Supervisor (2 FTE's) - field operations oversight	128,960	72,218	201,178	128,960	72,218	201,178
34	Fitter (6 FTE's) - reliable service	256,048	143,387	399,435	256,048	143,387	399,435
35	Operations Managers/Division Manager (4 FTE's) - operational and community support	310,280	173,757	484,037	310,280	173,757	484,037
36	Land Manager - oversee land purchases	41,600	23,296	64,896	14,560	8,154	22,714
37	Utility/Service Specialist (6 FTE's) - reliable service	266,683	149,342	416,025	266,683	149,342	416,025
38	Communication Specialist - coordinate school safety education programs	40,000	22,400	62,400	19,600	10,976	30,576
39	New Business Service Center Representative - support local builders	7,300	4,088	11,388	3,577	2,003	5,580
40	Commerical Sales Representative - timely response to customer feedback	60,000	33,600	93,600	60,000	33,600	93,600
41	Account Managers (2 FTE's) - timely response to customer feedback	72,900	40,824	113,724	72,900	40,824	113,724
42	Field Sales Representative - timely feedback to residential and commercial customers	60,000	33,600	93,600	42,000	23,520	65,520
43	Meter Reading Specialist - requirement for bill processing	25,000	14,000	39,000	25,000	14,000	39,000
44	CRM System Support Analyst (2 FTE's) - requirement for bill processing	75,200	42,112	117,312	75,200	42,112	117,312
45	Miscellaneous Billing Specialists (4 FTE's) - requirement for bill processing	106,920	59,875	166,795	52,391	29,339	81,730
46	Employee Adjustment	$ 3,667,226	$ 2,053,647	$ 5,720,873	$ 2,296,109	$ 1,285,821	$ 3,581,930

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Human Resource Programs

Line No.	Category	
1	Pro Forma Human Resource Programs	$ 183,750

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Workforce Aging Costs

Line No.	Category		
1	Pro Forma Workforce Aging Costs	$	535,687

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pipeline Safety Act Costs

Line No.	Category		
1	Pro Forma Pipeline Safety Act Cost Recoveries (A08)		$ 896,964
2	Test Year Pipeline Safety Act Cost Recoveries Billed (A08)	$ 638,145	
3	Unbilled Recoveries [(A)]	66,152	
4	Test Year Pipeline Safety Act Cost Recoveries (Line 2 + Line 3)		$ 704,297
5	Pro Forma Increase in Pipeline Safety Act Recoveries (Line 1 - Line 4)		$ 192,667
6	Less: Indiana Utility Receipts Taxes		1.53%
7	Pro Forma Increase in Pipeline Safety Act Costs (Line 5 - (Line 5 * Line 6)		$ 189,719

[(A)] - Expense associated with Unbilled Sales Revenue, which was removed in entry A06.

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Energy Efficiency Funding Costs

Line No.	Category		
1	Pro Forma Energy Efficiency Funding Costs (A09)		$ 3,647,933
2	Test Year Energy Efficiency Funding Costs Billed (A09)	$ 172,609	
3	Unbilled Recoveries [(A)]	314,274	
4	Test Year Energy Efficiency Funding Costs (Line 2 + Line 3)		$ 486,883
5	Pro Forma Increase in Energy Efficiency Funding Costs (Line 1 - Line 4)		$ 3,161,050
6	Less: Indiana Utility Receipts Taxes		1.53%
7	Pro Forma Increase in Energy Efficiency Funding Costs (Line 5 - (Line 5 * Line 6)		$ 3,112,686
8	Less: Depreciation Recovery Captured in Adjustment A41		57,308
9	Pro Forma Increase in Energy Efficiency Funding Costs (Line 7 - Line 8)		$ 3,055,378

[(A)] - Expense associated with Unbilled Sales Revenue, which was removed in entry A06.

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma for Gas Storage Facility Maintenance Expense

Line No.	Category	
1	Pro Forma for Gas Storage Facility Maintenance Expense	$ 343,488

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Distribution Maintenance

Line No.	Category		
1	Pro Forma Distribution Maintenance Expense	$	2,304,600
2	Less: Test Year Distribution Maintenance Expense		135,446
3	Pro Forma Increase in Distribution Maintenance Expense	$	2,169,154

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Regulator Station Maintenance Expense

Line No.	Category		
1	Pro Forma Regulator Station Maintenance Expense	$	1,311,433
2	Less: Test Year Regulator Station Maintenance Expense		58,215
3	Pro Forma Increase in Regulator Station Maintenance Expense	$	1,253,218

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Meter Maintenance Expense

Line No.	Category	
1	Pro Forma Increase to Reflect Meter Maintenance Expense	$ 1,275,212

Petitioner's Exhibit No. MSH-3
Adjustment A26

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Uncollectible Accounts

Line No.	Category		
1	Going Level Present Rate Revenue	$	821,888,922
2	Three Year Average of Actual Write-off's as a Percent of Revenues		0.91%
3	Pro Forma Uncollectible Accounts Expense	$	7,479,189
4	Less: Test Year Uncollectible AccountsExpense		7,547,722
5	Pro Forma Decrease in Uncollectible AccountsExpense	$	(68,533)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Miscellaneous Billing Expense

Line No.	Catergory	
1	Pro Forma Miscellaneous Billing Expense	$ 5,827,312
2	Less: Test Year Miscellaneous Billing Expense	5,605,322
3	Pro Forma Increase in Miscellaneous Billing Expense	$ 221,990

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Increase in Customer Contact Center Expenses

Line No.	Category		
1	Pro Forma Customer Contact Center Expenses	$	11,441,841
2	Less: Test Year Customer Contact Center Expenses		11,636,208
3	Pro Forma Increase in Customer Contact Center Expenses	$	(194,367)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Safety Communication Expense

Line No.	Category	
1	Pro Forma Increase to Reflect Safety Communication Expense	$ 719,424

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Increase in Economic Development Expense

Line No.	Category		
1	Pro Forma Economic Development Expense	$	545,974
2	Test Year Economic Development Expense		257,711
3	Pro Forma Increase to Reflect Increase in Economic Development Expense	$	288,263

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Increase in Information Technology Expenses

Line No.	Category		
1	Pro Forma Information Technology Maintenance and Other Costs	$	1,047,500
2	Less: Test Year Information Technology Maintenance and Other Costs		618,776
3	Pro Forma Increase in Information Technology Maintenance and Other Costs	$	428,724

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Increase in Information Technology Expenses

Line No.	Category	Test Year Expense	Pro Forma Expense	Pro Forma Adjustment
	Total Information Technology Expense:			
1	Computer Operations - Maintenance	$ 50,000	$ 91,500	$ 41,500
2	Computer Operations - Other Materials	-	3,200	3,200
3	Systems Integration - Maintenance	285,700	410,514	124,814
4	Systems Integration - Other Materials/Fees	7,802	21,700	13,898
5	Network and Telecommunications - Maintenance	505,819	701,165	195,346
6	Network and Telecommunications - Tower Rental	112,745	123,796	11,051
7	Network and Telecommunications - Other Materials	-	15,000	15,000
8	Network and Telecommunications - One Time Tax Credit	(84,625)	-	84,625
9	E-Business - Maintenance	114,277	169,994	55,717
10	E-Business - Annual Fees	725	2,000	1,275
11	Customer Information Systems - Maintenance	-	9,850	9,850
12	Energy Delivery Systems - Maintenance	330,689	662,521	331,832
13	Energy Delivery Systems - Other	12,126	-	(12,126)
14	Enterprise Resource Planning - Maintenance	50,000	224,805	174,805
15	Total Information Technology Expense Adjustment	$ 1,385,259	$ 2,436,045	$ 1,050,786
	Allocated to Vectren North:			
16	Computer Operations - Maintenance	$ 21,500	$ 39,345	$ 17,845
17	Computer Operations - Other Materials	-	1,376	1,376
18	Systems Integration - Maintenance	99,995	143,680	43,685
19	Systems Integration - Other Materials/Fees	2,731	7,595	4,864
20	Network and Telecommunications - Maintenance	185,693	257,689	71,996
21	Network and Telecommunications - Tower Rental	112,745	123,796	11,051
22	Network and Telecommunications - Other Materials/Credits	-	5,250	5,250
23	Network and Telecommunications - One Time Tax Credit	(29,619)	-	29,619
24	E-Business - Maintenance	39,998	59,498	19,500
25	E-Business - Annual Fees	254	700	446
26	Customer Information Systems - Maintenance	-	4,827	4,827
27	Energy Delivery Systems - Maintenance	162,037	324,906	162,869
28	Energy Delivery Systems - Other	5,942	-	(5,942)
29	Enterprise Resource Planning - Maintenance	17,500	78,838	61,338
30	Total Information Technology Expenses Allocated to Vectren North	$ 618,776	$ 1,047,500	$ 428,724

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Amortization of Rate Case Expenses

Line No.	Category		
1	Pro Forma Rate Case Amortization Expense	$	308,667
2	Less: Test Year Rate Case Amortization Expense		188,078
3	Pro Forma Increase in Rate Case Amortization Expense	$	120,589

VECTREN NORTH
PROFORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Amortization of Rate Case Expenses

Line No.			
1	Deferred Rate Case Expense Balance at December 31, 2006	$	172,405
2	Less: Expected Amortization January 2007 through December 2007		(172,405)
3	Deferred Rate Case Expense Balance at December 31, 2007	$	-
4	Expected Rate Case Expenses	$	926,000
5	Amortization Period (Years)		3
6	Pro Forma Rate Case Amortization Expense (Line 3 + Line 4 / Line 5)	$	308,667

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Amortization of the Pipeline Safety Act Cost Deferral

Line No.	Category		
1	Estimated Deferred Balance in Accordance with Cause No. 42598	$	5,595,480
2	Amortization Period (Years)		3
3	Annual Amortization of Deferred Pipeline Safety Act Costs	$	1,865,160

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2006

Supporting Schedule for Amortization of the Pipeline Safety Act Cost Deferral

Line No.				
1	Actual deferred expenses per Books at December 31, 2006	$	5,669,331	
2	Less: Nonincremental Expense through December 31, 2006		(39,194)	
3	Less: Variance from Year One Filing to be Recovered in subsequent filing		(189,719)	a)
4	Deferrals to be Recovered	$	5,440,418	
5	Plus: Estimated Costs January 1, 2007 through December 31, 2007		3,538,302	b)
6	Less: Estimated Recoveries from Existing Rates - January 1, 2007 through December 31, 2007		(883,240)	c)
7	Less: 2007 PSA Filing		(2,500,000)	d)
8	Estimated Deferred Balance in Accordance with Cause No. 42598	$	5,595,480	

a) $896,964 filed in Cause No. 42909, reduced for IURT, less recoveries of $693,521 (see Adjustment A20)
b) Estimated costs based on High Consequence Area Mileage and scheduled assessments
c) Year One Filing rate recovery based on Cause No. 42909 - rates still in effect for 2007
d) Annual cap on recoveries

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Property and Risk Insurance Expense

Line No.	Category		
1	Pro Forma Property and Risk Insurance Expense	$	1,690,160
2	Less: Test Year Property and Risk Insurance Expense		1,805,218
3	Pro Forma Decrease in Property and Risk Insurance Expense	$	(115,058)

VECTREN NORTH

FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Property and Risk Insurance Pro Forma Adjustment

Line No.			
	Risk Insurance Based on Actual 2006-2007 Premiums		
	Common Risk Insurance Premiums:		
1	Workers Compensation	$ 256,400	
2	Automobile Liability	218,448	
3	Excess Liability	1,661,963	
4	Directors & Officers Liability	1,184,334	
5	Blanket Crime	19,898	
6	Fiduciary Liability	167,363	
7	Miscellaneous Liability	1,917	
8	Total Pro-Forma Risk Insurance Expense	$ 3,510,323	
9	Allocation Factor to Vectren North	35%	
10	Total Vectren North Pro Forma Risk Insurance Expense	$ 1,228,613	$ 1,228,613
	Miscellaneous Bond Insurance Based on Actual 2006 Premiums Paid		
11	Bond Insurance		$ 11,810
	Property Insurance Based on Actual 2006-2007 Premiums		
	Above Ground Property Insurance Premiums:		
12	Property Insurance -- Above Ground Property	$ 1,298,339	
13	Allocation Factor to Vectren North	8.5%	
14	Total Pro Forma Vectren North Property Insurance	$ 110,359	$ 110,359
	Below Ground Property Insurance Premiums:		
15	Property Insurance -- Below Ground Property	$ 595,400	
16	Allocation Factor to Vectren North	57%	
17	Total Vectren North Pro Forma Property Insurance Expense	$ 339,378	$ 339,378
18	Total Vectren North Pro-Forma Property Insurance Expense (Sum of Lines 14 and 17)		$ 449,737
19	Total Pro Forma Property and Risk Insurance Expense Allocated to Vectren North (Lines 10, 11 and 18)		$ 1,690,160

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Claims Expense

Line No.	Category		
1	Pro Forma Claims Expense	$	878,498
2	Less: Test Year Claims Expense		227,856
3	Pro Forma Increase in Claims Expense	$	650,642

VECTREN NORTH
PROFORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Claims Expense Pro Forma Adjustment

Line No.	Claims Paid and Major Claims Expense				
1	12 months ended December 31, 2006	$	190,407		
2	12 months ended December 31, 2005		840,095		
3	12 months ended December 31, 2004		350,314		
4	12 months ended December 31, 2003		523,916		
5	12 months ended December 31, 2002		730,763		
6	Total Claims Paid and Major Claim Expense During Last Five Years	$	2,635,495		
7	Actual Claims Experience Amortized Over Three Year Period (Line 6 divided by 3)			$	878,498

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Rent Expense
(Other Cost Reductions)

Line No.	Category	
1	Pro Forma Decrease in Rent Expense from Former Corporate Headquarters	$ (427,956)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Pro Forma Cost Allocations

Line No.	Category		
1	Pro Forma Change in Cost Allocations	$	(96,648)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Cost Allocations Pro Forma Adjustment

Line No.			
	Test Year		
1	A&G Credit	$	(1,295,004)
2	Change in Allocation Drivers		744,811
3	Adjustment to Charges in Cost Centers		1,035,773
4	Test Year Impacts	$	485,580
	Pro Forma		
5	A&G Credit	$	(1,347,500)
6	Change in Allocation Drivers		686,523
7	Adjustment to Charges in Cost Centers		1,049,909
8	Pro Forma Impacts	$	388,932
9	Pro Forma Change in Cost Allocations (Line 8 - Line 4)	$	(96,648)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for Indiana Utility Regulatory Commission (IURC) Fee

Line No.	Category		
1	Pro Forma Revenue	$	821,888,922
2	IURC Rate		0.11%
3	Pro Forma IURC Fees	$	904,078
4	Less: Test Year IURC Fees		784,275
5	Pro Forma Increase in IURC Fees	$	119,803

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment to Reflect Asset Charge

Line No.			
1	Utility Holdings Gross Plant Balance at December 31, 2006	$	247,868,074
2	Accumulated Reserve for Depreciation		(109,790,210)
3	Utility Holdings Net Plant Balance at December 31, 2006	$	138,077,864
4	Pro Forma Weighted Average Cost of Capital Grossed Up for Income Taxes		12.27%
5	Asset Cost-Return and Income Taxes (Line 3 x Line 4)	$	16,942,154
6	Total Depreciation Expense		21,450,829
7	Total Property Taxes		1,211,604
8	Total Charges	$	39,604,587
9	Blended Allocation Factor to Vectren North		39.44%
10	Total Pro Forma Asset Charge (Line 8 x Line 9)	$	15,620,049
11	Less Test Year Asset Charge		15,141,583
12	Pro Forma Increase in Asset Charge	$	478,466

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Calculation of Weighted Average Cost of Capital

Line No.	WACC	%	Gross-up for taxes	Pre-tax WACC
1	Equity	5.63%	59.475%	9.47%
2	LTD	2.68%		2.68%
3	Other (Equity, Customer Deposits)	0.12%		0.12%
4	Weighted Average Cost of Capital	8.43%		12.27%
5	One	100.00%		
6	State Income Tax Rate	8.50%		
7	One Minus State Income Tax Rate		91.50%	
8	One	100.00%		
9	Federal Income Tax Rate	35.00%		
10	One Minus Federal Income Tax Rate		65.00%	
11	Gross-up Factor			59.475%

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Pro Forma Adjustment to Depreciation Expense

Line No.	Category		
1	Pro Forma Depreciation Expense	$	50,435,116
2	Less: Test Year Depreciation Expense		48,457,535
3	Pro Forma Increase in Depreciation Expense	$	1,977,581

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Depreciation Pro Forma Adjustment

DEPRECIABLE BALANCE
As of 12/31/06

Line No.		Plant In Service Balance	CCNC Balance	Estimated Additions	Annual Deprec. Rate	Annual Depreciation
1	301 Organization	$ 34,216	$ 257,428	$ -	-	$ -
2	302 Franchise and Consents	2,266			0.00	-
3	303 Miscellaneous Intangible Plant	977,595			6.67	65,206
4	304 Land and Land Rights	207,282			0.00	-
5	305 Structures & Improvements	1,269,072			3.74	47,463
6	311 Liquefied Petroleum Gas Equipment	9,531,653			3.75	357,437
7	332 Field Lines		87,838		2.65	2,328
8	350.1 Land	208,076			0.00	-
9	350.2 Rights-of-Way	243,290			2.66	6,472
10	351 Compressor Station Structures & Improvements	513,080	8,774		3.65	19,048
11	351 Measuring & Regulating Station Structures & Improvements	74,487			4.22	3,143
12	351 Other Structures & Improvements	1,003,628	1,991		3.54	35,599
13	352 Wells	6,781,053	18,074		3.50	237,969
14	352 Wells - Unionville	1,138,487			2.95	33,585
15	352 Wells - Sellersburg	440,396			2.95	12,992
16	352 Wells - Wolcott	1,366,836			2.95	40,322
17	352.1 Storage Leaseholds & Rights	613,626			2.53	15,525
18	352.2 Reservoirs	1,787,682			3.05	54,524
19	352.3 Nonrecoverable Natural Gas	2,034,067			2.95	60,005
20	353 Lines	3,372,009	16,213		3.28	111,134
21	354 Compressor Station EquipMent	3,791,128	43,333		4.58	175,618
22	355 Measuring & Regulating Equipment	1,262,558	59,106		4.65	61,457
23	356 Purification Equipment	10,412,722	15,628		4.52	471,361
24	365.1 Land and Land Rights		81,843		0.00	-
25	365.2 Rights-of-Way	789,609	1,928,439	1,850,000	2.06	94,102
26	366 Measuring & Regulating Station Structures and Improvements	9,349	13,136		4.22	949
27	367 Mains	11,916,324	14,774,267	31,750,000	2.84	1,659,713
28	369 Measuring & Regulating Station Equipment	1,222,731	2,408,326	1,100,000	3.76	177,888
29	370 Communication Equipment	6,386			3.97	254
30	374 Land	505,841	20,010		0.00	-
31	374 Land Rights	10,074,946	658,206		2.06	221,103
32	375 Structures & Improvements	2,416,970	120,444		3.46	87,795
33	376 Mains	473,397,880	34,734,189		2.84	14,430,951
34	377 Compressor Station Equipment	1,541,962	20,631		4.01	62,660
35	378 Measuring & Regulating Station Equipment-General	24,022,680	1,795,093		3.38	872,641
36	379 Measuring & Regulating Station Equipment-City Gate	10,146,738	179,191		3.76	388,255
37	380 Services	406,754,971	917,862		5.25	21,402,824
38	381 Meters	67,008,120	149,127		2.62	1,759,520
39	382 Meter Installations	49,194,760	706,557		5.32	2,654,750
40	383 House Regulators	18,994,903	32,120		4.83	919,005
41	384 House Regulator Installations	18	17,397		0.00	-
42	385 Industrial Measuring & Regulating Station Equipment	37,576,637	766,150		3.90	1,495,369
43	387 Other Equipment		153,668		3.81	5,855
44	389 Land and Land Rights	1,029,249	165,257		0.00	-
45	390 Structures & Improvements	21,956,139	2,754,095		2.88	711,655
46	391 Office Furniture and Equipment-Electronic Equipment	235,979	1,710		12.86	30,567
47	391 Office Furniture and Equipment-Fixtures	2,144,058	45,955		3.50	76,650
48	392 Transportation Equipment-Light Trucks	3,975,410	3,826,876		10.08	786,470
49	392 Transportation Equipment-Trailers	700,689	163,184		5.45	47,081
50	392 Transportation Equipment-Heavy Trucks		388,828		0.00	-
51	393 Stores Equipment	1,826,727			3.11	56,811
52	394 Tools, Shop & Garage Equipment	5,462,146	121,442		3.99	222,785
53	395 Laboratory Equipment	2,839,382	40,907		4.40	126,733
54	396 Power Operated Equipment	4,713,463	394,994		7.29	372,407
55	397 Communication Equipment	4,161,267			3.97	165,202
56	398 Miscellaneous Equipment	214,544	40,647		3.81	9,723
57		$ 1,211,905,087	$ 67,928,935	$ 34,700,000		$ 50,650,903
58	Less:					
59	392 Transportation Equipment (FERC 184)	4,676,099	4,378,888			833,552
60	Plus:					
61	Amortization of Leasehold Improvements	353,599				50,514
62	Amortization of Acquisition Adjustments	20,299,804				504,732
63	Regulatory Asset - Nexus Audit Tool (See A21)	250,073				62,518
64	Depreciation Expense					$ 50,435,116

Estimated Additions:	365.2 Rights-of-Way	367 Mains	369 Meas & Reg Sta Eq	Total
Greencastle	$ 350,000	$ 8,050,000	$ 500,000	$ 8,900,000
Greensburg (Honda)	1,500,000	23,700,000	600,000	25,800,000
	$ 1,850,000	$ 31,750,000	$ 1,100,000	$ 34,700,000

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment of State Income Tax at Current Rates

Line No.	Catergory			
1	Pro Forma Gross Margin		$	243,236,540
2	Operation and Maintenance Expenses			(98,942,811)
3	Asset Charge			(15,620,049)
4	Depreciation			(50,435,116)
5	Property Taxes			(10,117,719)
6	Income Before IURT and Income Taxes		$	68,120,845
7	Less: Interest Synchronization			(21,976,095)
8	Add: Permanent Differences			
9	Book Depreciation on Non-Deferred Basis	$ 503,089		
10	Medicare Act Subsidy	(71,680)		
11	Contributions	297,500		
12	Other Non Deductible Expenses	(157,063)		
13	Permanent Differences		$	571,846
14	Income Before State Taxes		$	46,716,596
15	State Income Tax Rate			8.5%
16	Pro Forma Provision for State Income Taxes (Line 14 x Line 15)		$	3,970,911
17	Add: Flowback			223,630
18	Pro Forma State Income Taxes (Line 15 + Line 16)		$	4,194,541
19	Less: Test Year Provision for State Income Taxes			4,385,796
20	Pro Forma Decrease in State Income Taxes at Current Rates		$	(191,255)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment of Federal Income Tax at Current Rates

Line No.	Category		
1	Income Before IURT and Income Taxes		$ 68,120,845
2	Less: Interest Synchronization		(21,976,095)
3	Add: Permanent Differences		
4	Book Depreciation on Non-Deferred Basis	$ 503,089	
5	Medicare Act Subsidy	(71,680)	
6	Other Non Deductible Expenses	(157,063)	
7	Permanent Differences		$ 274,346
8	IURT		(11,401,722)
9	Pro Forma Provision for State Income Taxes (A41, Line 15)		(3,970,911)
10	Federal Taxable Income		$ 31,046,463
11	Federal Income Tax Rate		35%
12	Federal Income Taxes (Line 10 x Line 11)		$ 10,866,262
13	Less: Amortization of Investment Tax Credit		(814,109)
14	Less: Flowback		(319,336)
15	Pro Forma Provision for Federal Income Taxes (Line 12 + Line 13 + Line 14)		$ 9,732,817
16	Less: Test Year Provision for Federal Income Taxes		10,555,927
17	Pro Forma Decrease in Federal Income Taxes at Current Rates		$ (823,110)

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for Indiana Utility Receipts Tax

Line No.	Category		
1	Going Level Present Rate Revenue	$	821,888,922
2	Less: Uncollectible Accounts Expense		(7,479,189)
3	Statutory Exemption		(1,000)
4	Pro Forma Margins Subject to Indiana Utility Receipts Tax	$	814,408,733
5	IURT tax rate		1.40%
6	Pro Forma Utility Receipts Tax	$	11,401,722
7	Less: Test Year Indiana Utility Receipts Tax		10,710,172
8	Pro Forma Increase in Indiana Utility Receipts Tax	$	691,550

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for Property Tax Expense

Line No.	Category	
1	Pro Forma Property Tax Expense	$ 10,117,719
2	Less: Test Year Property Tax Expense	9,565,956
3	Pro Forma Increase in Property Tax Expense	$ 551,763

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Supporting Schedule for Property Tax Pro Forma Adjustment

Line No.			
1	2006 Property Tax Payments - Vectren North	$	9,656,091
2	Less: 2006 Property Tax Payments paid on Former Corporate Headquarters		235,749
3	Adjusted 2006 Property Tax Payments - Vectren North	$	9,420,342
4	Three Year Compound Annual Growth in Rate and Assessed Value		7.40%
5	Pro Forma Property Tax Expense - Vectren North	$	10,117,719

VECTREN NORTH
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at December 31 , 2006

Revenue Increase Based on Net Original Cost Rate Base

Line No.			
1	Net Original Cost Rate Base	$	790,507,009
2	Rate of Return		8.43%
3	Required Net Operating Income (Line 1 x Line 2)	$	66,639,741
4	Pro Forma Net Operating Income		42,791,765
5	Increase in Net Operating Income	$	23,847,976
6	Effective Incremental Revenue/NOI Conversion Factor		58.0%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5/Line 6)	$	41,140,866

8	One		1.000000			
9	Less: IURC Fee		0.001100			
10	Less: Bad Debt		0.009100			
11	One Less Bad Debt, IURC Fee and IURT			0.989800		
12	One	1.000000				
13	Less: Bad Debt	0.009100				
14	Taxable Adjusted IURT		0.990900			
15	IURT Rate		0.014000			
16	Adjusted IURT			0.013873		
17	One	1.000000				
18	Less: IURC Fee	0.001100				
19	Less: Bad Debt	0.009100				
20	Taxable Adjusted Gross Income Tax		0.989800			
21	Adjusted Gross Income Tax Rate		0.085000			
22	Adjusted Gross Income Tax			0.084133		
23	Line 11 less line 22				0.891794	
24	One			1.000000		
25	Less: Federal Income Tax Rate			0.350000		
26	One Less Federal Income Tax Rate				0.650000	
27	Effective Incremental Revenue/NOI Conversion Factor (line 23 times line 26)					58.0%

VECTREN NORTH
Statement of Gas Property
Original Cost Ratebase at December 31, 2006

Line No.	Activity (FERC) No.	Description		Gas Plant Per Books at December 31, 2006		Eliminations		As Adjusted Pro Forma Rate Base December 31, 2006
		Utility Plant						
1	101	In Service - Unitized	$	1,211,905,087	$	-	$	1,211,905,087
2	104	Utility Plant Leased to Others		-		-		-
3	105	Property Held for Future Use		443,706		(443,706)		-
4	106	Completed Const. Not Classified		67,928,935		-		67,928,935
5	106	Greencastle 12" Transmission Line		-		8,900,000		8,900,000
6	106	Greensburg Pipeline & System Upgrade to Support Honda Plant		-		25,800,000		25,800,000
7	107	Const. Work in Progress		26,020,433		(26,020,433)		-
8	117	Cushion Gas		8,581,320		-		8,581,320
9			$	1,314,879,481	$	8,235,861	$	1,323,115,342
		Accumulated Depreciation						
10	108	Utility Plant		(621,741,619)		-		(621,741,619)
			$	693,137,862	$	8,235,861	$	701,373,723
11	114	Acquistion Adjustment (Westport, Terre Haute, Richmond)		22,538,065		(2,238,261)		20,299,804
12	115	Accumulated Depreciation Acquisition Adj's		(9,204,469)		908,891		(8,295,578)
13		Net Acquisition Adjustment	$	13,333,596	$	(1,329,369)	$	12,004,226
14		Net Utility Plant	$	706,471,458	$	6,906,491	$	713,377,949
		Material & Supplies (13 Month Average)						
15	151	Liquefied Petroleum Gas	$	780,037	$	-	$	780,037
16	154	Utility Material & Supplies		2,209,704		-		2,209,704
17	163	Store Expense		231,535		-		231,535
18	164	Gas in Underground Storage		12,027,072		-		12,027,072
19	165	Prepaid Gas Delivery		61,880,712		-		61,880,712
20		Total Material & Supplies	$	77,129,060	$	-	$	77,129,060
21		TOTAL	$	783,600,518	$	6,906,491	$	790,507,009

VECTREN NORTH
Capital Structure and Cost of Capital
Twelve months ending December 31, 2006

Line No.	Type of Capital	Amount ($000's)	Percent	Cost	WCOC
1	**Long-Term Debt**				
2	Publicly Held	$ 127,500	13.37%		
3	Notes to VUHI	243,838	25.56%		
4	Total Long-Term Debt	$ 371,338	38.93%	6.86%	2.68%
5	**Common Equity**				
6	Common Stock	$ 367,995	38.58%		
7	Retained Earnings	99,286	10.41%		
8	Common Shareholder's Equity	$ 467,281	48.99%	11.50%	5.63%
9	**Investor Provided Capital**	838,619	87.92%		8.31%
10	**Customer Deposits**	19,842	2.08%	5.00%	0.10%
11	**Cost Free Capital:**				
12	Deferred Income Taxes	$ 74,333	7.79%		
13	Customer Advances for Construction	2,304	0.24%		
14	Pre-1971 Investment Tax Credit	87	0.01%		
15	SFAS 106	16,928	1.78%		
16	Total Cost Free Capital	$ 93,652	9.82%	0.00%	0.00%
17	**Job Development Investment Tax Credit (Post-1971)**	$ 1,731	0.18%	9.45%	0.02%
18	**Total Capitalization**	$ 953,844	100.00%		
19	**Rate of Return**				8.43%

Investor Provided Capital

Line No.		Amount ($000's)	Percent	Cost	WCOC
20	Long-Term Debt	$ 371,338	44.28%	6.86%	3.04%
21	Common Equity	467,281	55.72%	11.50%	6.41%
22	Total Capitalization	$ 838,619	100.00%		9.45%

Interest Synchronization

Line No.		Percent	Cost	Weighted Cost
23	Long-term Debt	38.93%	6.86%	2.67%
24	Customer Deposits	2.08%	5.00%	0.10%
25	Interest Component of ITC	0.18%	6.86%	0.01%
26	Total			2.78%
27	Original Cost Rate Base			$ 790,507,009
28	Synchronized Interest Expense			$ 21,976,095

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for Uncollectible Accounts on Revenue Increase

Line No.	Category		
1	Pro Forma Increase in Revenue Requirement	$	41,140,866
2	Three Year Average of Actual Write-offs as a Percent of Revenue		0.91%
3	Pro Forma Increase in Uncollectible Accounts Expense	$	374,382

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for IURC Fees on Revenue Increase

Line No.	Category		
1	Pro Forma Increase in Revenue Requirement	$	41,140,866
2	Indiana IURC Rate		0.11%
3	Pro Forma Increase in IURC Fees	$	45,255

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment of State Income Tax at Proposed Rates

Line No.	Category		
1	Pro Forma Increase in Requirement Revenue	$	41,140,866
2	Less: Additional IURC Fee		(45,255)
3	Less: Additional Uncollectible Accounts Expense		(374,382)
4	Income Before IURT and Income Taxes	$	40,721,229
5	State Tax Rate		8.5%
6	Pro Forma Increase in State Income Tax at Proposed Rates	$	3,461,304

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment of Federal Income Tax at Proposed Rates

Line No.	Category		
1	Pro Forma Increase in Requirement Revenue	$	41,140,866
2	Less: Additional IURC Fee		(45,255)
3	Less: Additional IURT		(570,731)
4	Less: Additional State Income Taxes		(3,461,304)
5	Less: Additional Uncollectible Accounts Expense		(374,382)
6	Incremental Federal Taxable Income	$	36,689,194
7	Federal Tax Rate		35%
8	Pro Forma Increase in Federal Income Tax at Proposed Rates	$	12,841,218

VECTREN NORTH
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

Adjustment for Indiana Utility Receipts Tax for Additional Revenue Requirement

Line No.	Category		
1	Pro Forma Increase in Revenue Requirement	$	41,140,866
2	Less: Uncollectible Expense on Revenue Increase		(374,382)
3	Revenue Increase Subject to Indiana Utility Receipts Tax	$	40,766,484
4	Indiana Utility Receipts Tax Rate		1.40%
5	Pro Forma Increase in Indiana Utility Receipts Tax	$	570,731

VECTREN NORTH
FERC Summary - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

	A Test Year - Actual 12 mos 12/31/06	E Proforma Adjustment	Proforma Adj Reference	F = A + E Actual w/Pro-Forma
Manufactured Gas Production Operation				
710 Operation Supervision & Engineering	$ -	$ -		$ -
712 Other Power Expenses	$ 548	$ 23	A11 , A14 , A15	$ 571
717 Liquified Petroleum Gas Expenses	$ 71,241	$ 2,045	A11 , A14 , A15	$ 73,286
728 Liquified Petroleum Gas	$ -	$ -		$ -
735 Misc Production Expenses	$ 19,115	$ 691	A11 , A14 , A15	$ 19,806
736 Rents	$ -	$ -		$ -
Total Manufactured Gas Production Operation	$ 90,904	$ 2,759		$ 93,663
Manufactured Gas Production Maintenance				
740 Maintenance Supervision & Engineering	$ -	$ -		$ -
741 Maintenance of Structures & Improvements	$ 32,948	$ 1,137	A11 , A14 , A15	$ 34,085
742 Maintenance of Production Equipment	$ 202,796	$ 3,085	A11 , A14 , A15	$ 205,881
Total Manufactured Gas Production Maintenance	$ 235,744	$ 4,222		$ 239,966
Production Operation				
750 Operation Supervision & Engineering	$ -	$ -		$ -
752 Gas Wells Expenses	$ -	$ -		$ -
753 Field Lines Expenses	$ -	$ -		$ -
Total Production Operation	$ -	$ -		$ -
Production Maintenance				
761 Maintenance Supervision & Engineering	$ -	$ -		$ -
763 Maintenance of Producing Gas Wells	$ -	$ -		$ -
764 Maintenance of Field Wells	$ -	$ -		$ -
Total Production Maintenance	$ -	$ -		$ -
Stored Gas Operations				
814 Operation Supervision and Engineering	$ 89,573	$ 4,006	A11 , A14 , A15	$ 93,579
815 Maps and Records	$ 829	$ 21	A11 , A14 , A15	$ 850
816 Wells Expenses	$ 133,024	$ 299,431	A11 , A14 , A15 , A22	$ 432,455
817 Lines Expense	$ 77,475	$ 2,941	A11 , A14 , A15	$ 80,416
818 Compressor Station Expense	$ 111,446	$ 4,313	A11 , A14 , A15	$ 115,759
819 Compressor Station Fuel & Power	$ 3,044	$ 120	A11 , A14 , A15	$ 3,164
820 Measuring and Regulating Station	$ 5,289	$ 208	A11 , A14 , A15	$ 5,497
821 Purification Expenses	$ 195,587	$ 6,900	A11 , A14 , A15	$ 202,487
822 Exploration and Development	$ -	$ -		$ -
824 Other Expenses	$ -	$ -		$ -
825 Storage Well Royalties	$ -	$ -		$ -
826 Rents	$ 143,592	$ 662	A11 , A14 , A15	$ 144,254
Total Stored Gas Operations	$ 759,857	$ 318,602		$ 1,078,459
Stored Gas Maintenance				
830 Maintenance Supervision & Engineering	$ -	$ -		$ -
831 Maintenance of Structures and Improvements	$ 28,009	$ 46,865	A11 , A14 , A15 , A22	$ 74,874
832 Maintenance of Reservoirs and Wells	$ 28,195	$ 475	A11 , A14 , A15	$ 28,670
833 Maintenance of Lines	$ 57,065	$ 1,312	A11 , A14 , A15	$ 58,377
834 Maintenance of Compression Station Equipment	$ 128,747	$ 4,930	A11 , A14 , A15	$ 133,677
835 Maintenance of Meas. & Reg. Station Equipment	$ 2,832	$ 111	A11 , A14 , A15	$ 2,943
836 Maintenance of Purification Equipment	$ 235,653	$ 7,264	A11 , A14 , A15	$ 242,917
837 Maintenance of Other Equipment	$ -	$ -		$ -
Total Stored Gas Maintenance	$ 480,502	$ 60,957		$ 541,459
Transmission Operation				
850 Operation Supervision and Engineering	$ 383,822	$ 103,996	A17 , A19	$ 487,818
851 System Control and Load Dispatching	$ (21,670)	$ -		$ (21,670)
853 Compressor Station Labor and Expenses	$ 4,231	$ 165	A11 , A14 , A15	$ 4,396
856 Mains Expenses	$ 630,136	$ 2,198,156	A11 , A14 , A15 , A17 , A19 , A20 , A33	$ 2,828,292
857 Measuring and Regulating Station Expenses	$ 402,260	$ 6,460	A11 , A14 , A15	$ 408,720
859 Other Expenses	$ -	$ -		$ -
860 Rents	$ 32,121	$ 127	A11 , A14 , A15	$ 32,248
Total Transmission Operation	$ 1,430,900	$ 2,308,904		$ 3,739,804
Transmission Maintenance				
861 Maintenance Supervision and Engineering	$ -	$ -		$ -
862 Maintenance of Structures and Improvements	$ 35,059	$ 1,048	A11 , A14 , A15	$ 36,107
863 Maintenance of Mains	$ 757,950	$ 2,219,489	A11 , A14 , A15 , A17 , A23	$ 2,977,439
865 Maintenance of Measuring and Reg Station Equipment	$ 189,123	$ 4,335	A11 , A14 , A15	$ 193,458
866 Maintenance of Communication Equipment	$ -	$ -		$ -
867 Maintenance of Other Equipment	$ 57,539	$ 2,399	A11 , A14 , A15	$ 59,938
Total Transmission Maintenance	$ 1,039,671	$ 2,227,271		$ 3,266,942
Distribution Operations				
870 Operation Supervision and Engineering	$ 2,409,990	$ 1,637,492	A11 , A14 , A15 , A16 , A17 , A19	$ 4,047,482
871 Distribution Load Dispatching	$ -	$ -		$ -
872 Compressor Station Labor & Expenses	$ -	$ -		$ -
873 Compressor Station Fuel & Power	$ -	$ -		$ -
874 Mains and Services Expenses	$ 6,041,473	$ 303,013	A11 , A14 , A15 , A17 , A19	$ 6,344,486
875 Measuring and Regulating Stations Expenses-General	$ 347,085	$ 11,883	A11 , A14 , A15	$ 358,968
876 Measuring and Regulating Stations Expenses-Industrial	$ -	$ -		$ -
877 Measuring and Regulating Stations Expenses-City Gate Check Stations	$ -	$ -		$ -
878 Meter and House Regulator Expenses	$ 404,332	$ 15,934	A11 , A14 , A15	$ 420,266
879 Customer Installation Expenses	$ 7,005,870	$ 277,031	A11 , A14 , A15	$ 7,282,901
880 Other Expenses	$ 4,269,466	$ 941,354	A11 , A14 , A15 , A16 , A17 , A19 , A23 , A37	$ 5,210,820
881 Rents	$ 445,608	$ -		$ 445,608
Total Distribution Operations	$ 20,923,824	$ 3,186,707		$ 24,110,531

VECTREN NORTH
FERC Summary - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

	A Test Year - Actual 12 mos 12/31/06	E Proforma Adjustment	Proforma Adj Reference	F = A + E Actual w/Pro-Forma
Distribution Maintenance				
885 Maintenance Supervision and Engineering	$ 995,519	$ 40,313	A11 , A14 , A15	$ 1,035,832
886 Maintenance of Structures and Improvements	$ 1,566,216	$ 1,257,361	A11 , A14 , A15 , A24	$ 2,823,577
887 Maintenance of Mains	$ 2,369,994	$ 214,726	A11 , A14 , A15 , A17	$ 2,584,720
888 Maintenance of Compressor Station Equipment	$ 1,384	$ 18	A11 , A14 , A15	$ 1,402
889 Maintenance of Measuring and Regulating Station Equipment-General	$ 281,971	$ 5,511	A11 , A14 , A15	$ 287,482
890 Maintenance of Meas. & Reg. Station Equipment-Industrial	$ -	$ -		$ -
891 Maintenance of Meas. & Reg. Station Equipment-City Gate Check Stations	$ -	$ -		$ -
892 Maintenance of Services	$ 1,453,393	$ 53,233	A11 , A14 , A15 , A37	$ 1,506,626
893 Maintenance of Meters and House Regulators	$ 90,836	$ 1,277,599	A11 , A14 , A15 , A25	$ 1,368,435
894 Maintenance of Other Equipment	$ 178,884	$ 3,359	A11 , A14 , A15	$ 182,243
Total Distribution Maintenance	$ 6,938,197	$ 2,852,120		$ 9,790,317
Customer Accounts				
901 Supervision (Customer Accounts)	$ 1,010,394	$ 323,117	A11 , A14 , A15 , A17	$ 1,333,511
902 Meter Reading Expenses	$ 3,965,900	$ 172,027	A11 , A14 , A15 , A17 , A27	$ 4,137,927
903 Customer Records and Collection	$ 11,636,208	$ 379,014	A11 , A14 , A15 , A17 , A27 , A28	$ 12,015,222
904 Uncollectible Accounts	$ 7,547,722	$ (68,533)	A26	$ 7,479,189
905 Miscellaneous Customer Accounts	$ 561,418	$ 11,913	A11 , A14 , A15	$ 573,331
Total Customer Accounts	$ 24,721,642	$ 817,538		$ 25,539,180
Customer Service and Informational				
907 Supervision (Customer Service)	$ (32)	$ -		$ (32)
908 Customer Assistance Expenses	$ 346,321	$ 15,404	A11 , A14 , A15	$ 361,725
909 Informational and Instructional Expenses	$ 102,525	$ 750,000	A17 , A29	$ 852,525
910 Miscellaneous Customer Service and Informational	$ 211,837	$ 4,825	A11 , A14 , A15	$ 216,662
Total Customer Service and Informational Expenses	$ 660,652	$ 770,229		$ 1,430,881
Sales Expenses				
911 Supervision (Sales)	$ 4,294	$ 192	A11 , A14 , A15	$ 4,486
912 Demonstrating and Selling Expenses	$ 438,685	$ 591,536	A11 , A14 , A15 , A17 , A30	$ 1,030,221
913 Advertising Expenses	$ 361,467	$ 2,260,979	A21	$ 2,622,446
916 Miscellaneous Sales Expenses	$ 46,150	$ -		$ 46,150
Total Sales Expenses	$ 850,596	$ 2,852,707		$ 3,703,303
Administrative and General				
920 Administrative and General Salaries	$ 9,108,445	$ 2,042,797	A11 , A13 , A14 , A15 , A17	$ 11,151,242
921 Office Supplies and Expenses	$ 5,470,234	$ 3,272	A11 , A14 , A15 , A18 , A31 , A36 , A37	$ 5,473,506
922 Administrative Expenses Transferred-Credit	$ (1,295,004)	$ -		$ (1,295,004)
923 Outside Services Employed	$ 17,137,316	$ 1,412,517	A11 , A14 , A15 , A21 , A37 , A39	$ 18,549,833
924 Property Insurance	$ 477,220	$ (27,483)		$ 449,737
925 Injuries and Damages	$ 1,555,853	$ 563,067	A34 , A35	$ 2,118,920
926 Employee Pensions and Benefits	$ 30,678	$ -		$ 30,678
928 Regulatory Commission Expenses	$ 972,353	$ 240,392	A32 , A38	$ 1,212,745
930.1 General Advertising Expenses	$ -	$ -		$ -
930.2 Miscellaneous General Expenses	$ 1,598,935	$ 669,784	A12 , A37	$ 2,268,719
931 Rents	$ 44,356	$ (25,113)	A37	$ 19,243
932 Maintenance of General Plant	$ 1,030,441	$ 18,294	A11 , A14 , A15	$ 1,048,735
Total A & G Expenses	$ 36,130,828	$ 4,897,527		$ 41,028,355
Total Gas Operations and Maintenance Expenses	$ 94,263,317	$ 20,299,543		$ 114,562,860
Depreciation and Amortization				
403 Depreciation Expense	$ 48,452,325	$ 1,920,273	A40	$ 50,372,598
403.1 Depr Exp for Asset Retirement Costs	$ -	$ -		$ -
407.4 Amortization of Regulatory Assets	$ 5,210	$ 57,308	A40	$ 62,518
Total Depreciation and Amortization	$ 48,457,535	$ 1,977,581		$ 50,435,116
Other Taxes				
408.1 Taxes Other than Income Taxes	$ 20,276,128	$ 1,243,313	A43 , A44	$ 21,519,441
Total Other Taxes	$ 20,276,128	$ 1,243,313		$ 21,519,441

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

710 Operation Supervision & Engineering			
	$	-	
	$	-	
712 Other Power Expenses			
Labor Adjustments for Existing Headcount	$	27	A11
Pension Expense	$	(6)	A14
Postretirement Medical Expense	$	2	A15
	$	23	
717 Liquified Petroleum Gas Expenses			
Labor Adjustments for Existing Headcount	$	2,363	A11
Pension Expense	$	(480)	A14
Postretirement Medical Expense	$	162	A15
	$	2,045	
728 Liquified Petroleum Gas			
	$	-	
	$	-	
735 Misc Production Expenses			
Labor Adjustments for Existing Headcount	$	798	A11
Pension Expense	$	(162)	A14
Postretirement Medical Expense	$	55	A15
	$	691	
736 Rents			
	$	-	
	$	-	
740 Maintenance Supervision & Engineering			
	$	-	
	$	-	
741 Maintenance of Structures & Improvements			
Labor Adjustments for Existing Headcount	$	1,314	A11
Pension Expense	$	(267)	A14
Postretirement Medical Expense	$	90	A15
	$	1,137	
742 Maintenance of Production Equipment			
Labor Adjustments for Existing Headcount	$	3,565	A11
Pension Expense	$	(724)	A14
Postretirement Medical Expense	$	244	A15
	$	3,085	
750 Operation Supervision & Engineering			
	$	-	
	$	-	
752 Gas Wells Expenses			
	$	-	
	$	-	
753 Field Lines Expenses			
	$	-	
	$	-	
761 Maintenance Supervision & Engineering			
	$	-	
	$	-	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

763 Maintenance of Producing Gas Wells			
	$	-	
	$	-	
764 Maintenance of Field Wells			
	$	-	
	$	-	
814 Operation Supervision and Engineering			
Labor Adjustments for Existing Headcount	$	4,628	A11
Pension Expense	$	(939)	A14
Postretirement Medical Expense	$	317	A15
	$	4,006	
815 Maps and Records			
Labor Adjustments for Existing Headcount	$	24	A11
Pension Expense	$	(5)	A14
Postretirement Medical Expense	$	2	A15
	$	21	
816 Wells Expenses			
Labor Adjustments for Existing Headcount	$	2,244	A11
Pension Expense	$	(455)	A14
Postretirement Medical Expense	$	154	A15
Gas Storage Facilities Expense	$	297,488	A22
	$	299,431	
817 Lines Expense			
Labor Adjustments for Existing Headcount	$	3,397	A11
Pension Expense	$	(689)	A14
Postretirement Medical Expense	$	233	A15
	$	2,941	
818 Compressor Station Expense			
Labor Adjustments for Existing Headcount	$	4,983	A11
Pension Expense	$	(1,011)	A14
Postretirement Medical Expense	$	341	A15
	$	4,313	
819 Compressor Station Fuel & Power			
Labor Adjustments for Existing Headcount	$	139	A11
Pension Expense	$	(28)	A14
Postretirement Medical Expense	$	9	A15
	$	120	
820 Measuring and Regulating Station			
Labor Adjustments for Existing Headcount	$	241	A11
Pension Expense	$	(49)	A14
Postretirement Medical Expense	$	16	A15
	$	208	
821 Purification Expenses			
Labor Adjustments for Existing Headcount	$	7,972	A11
Pension Expense	$	(1,618)	A14
Postretirement Medical Expense	$	546	A15
	$	6,900	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

822 Exploration and Development			
	$	-	
	$	-	
824 Other Expenses			
	$	-	
	$	-	
825 Storage Well Royalties			
	$	-	
	$	-	
826 Rents			
Labor Adjustments for Existing Headcount	$	765	A11
Pension Expense	$	(155)	A14
Postretirement Medical Expense	$	52	A15
	$	662	
830 Maintenance Supervision & Engineering			
	$	-	
	$	-	
831 Maintenance of Structures and Improvements			
Labor Adjustments for Existing Headcount	$	1,000	A11
Pension Expense	$	(203)	A14
Postretirement Medical Expense	$	68	A15
Gas Storage Facilities Expense	$	46,000	A22
	$	46,865	
832 Maintenance of Reservoirs and Wells			
Labor Adjustments for Existing Headcount	$	548	A11
Pension Expense	$	(111)	A14
Postretirement Medical Expense	$	38	A15
	$	475	
833 Maintenance of Lines			
Labor Adjustments for Existing Headcount	$	1,516	A11
Pension Expense	$	(308)	A14
Postretirement Medical Expense	$	104	A15
	$	1,312	
834 Maintenance of Compression Station Equipment			
Labor Adjustments for Existing Headcount	$	5,696	A11
Pension Expense	$	(1,156)	A14
Postretirement Medical Expense	$	390	A15
	$	4,930	
835 Maintenance of Meas. & Reg. Station Equipment			
Labor Adjustments for Existing Headcount	$	128	A11
Pension Expense	$	(26)	A14
Postretirement Medical Expense	$	9	A15
	$	111	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

836 Maintenance of Purification Equipment			
Labor Adjustments for Existing Headcount	$	8,392	A11
Pension Expense	$	(1,703)	A14
Postretirement Medical Expense	$	575	A15
	$	7,264	
837 Maintenance of Other Equipment			
	$	-	
	$	-	
850 Operation Supervision and Engineering			
Additional Employees	$	100,589	A17
Aging Workforce	$	3,407	A19
	$	103,996	
851 System Control and Load Dispatching			
	$	-	
	$	-	
853 Compressor Station Labor and Expenses			
Labor Adjustments for Existing Headcount	$	191	A11
Pension Expense	$	(39)	A14
Postretirement Medical Expense	$	13	A15
	$	165	
856 Mains Expenses			
Labor Adjustments for Existing Headcount	$	12,110	A11
Pension Expense	$	(2,458)	A14
Postretirement Medical Expense	$	829	A15
Additional Employees	$	49,929	A17
Aging Workforce	$	82,867	A19
Pipeline Safety Act Costs	$	189,719	A20
Pipeline Safety Act Costs Amortization	$	1,865,160	A33
	$	2,198,156	
857 Measuring and Regulating Station Expenses			
Labor Adjustments for Existing Headcount	$	7,464	A11
Pension Expense	$	(1,515)	A14
Postretirement Medical Expense	$	511	A15
	$	6,460	
859 Other Expenses			
	$	-	
	$	-	
860 Rents			
Labor Adjustments for Existing Headcount	$	147	A11
Pension Expense	$	(30)	A14
Postretirement Medical Expense	$	10	A15
	$	127	
861 Maintenance Supervision and Engineering			
	$	-	
	$	-	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

862 Maintenance of Structures and Improvements			
Labor Adjustments for Existing Headcount	$	1,211	A11
Pension Expense	$	(246)	A14
Postretirement Medical Expense	$	83	A15
	$	1,048	
863 Maintenance of Mains			
Labor Adjustments for Existing Headcount	$	41,266	A11
Pension Expense	$	(8,375)	A14
Postretirement Medical Expense	$	2,825	A15
Additional Employees	$	49,929	A17
Distribution Maintenance	$	2,133,844	A23
	$	2,219,489	
865 Maintenance of Measuring and Reg Station Equipment			
Labor Adjustments for Existing Headcount	$	5,009	A11
Pension Expense	$	(1,017)	A14
Postretirement Medical Expense	$	343	A15
	$	4,335	
866 Maintenance of Communication Equipment			
	$	-	
	$	-	
867 Maintenance of Other Equipment			
Labor Adjustments for Existing Headcount	$	2,772	A11
Pension Expense	$	(563)	A14
Postretirement Medical Expense	$	190	A15
	$	2,399	
870 Operation Supervision and Engineering			
Labor Adjustments for Existing Headcount	$	97,106	A11
Pension Expense	$	(19,708)	A14
Postretirement Medical Expense	$	6,648	A15
Training Expense	$	24,800	A16
Additional Employees	$	1,525,239	A17
Aging Workforce	$	3,407	A19
	$	1,637,492	
871 Distribution Load Dispatching			
	$	-	
	$	-	
872 Compressor Station Labor & Expenses			
	$	-	
	$	-	
873 Compressor Station Fuel & Power			
	$	-	
	$	-	
874 Mains and Services Expenses			
Labor Adjustments for Existing Headcount	$	81,293	A11
Pension Expense	$	(16,499)	A14
Postretirement Medical Expense	$	5,565	A15
Additional Employees	$	149,788	A17
Aging Workforce	$	82,866	A19
	$	303,013	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

875 Measuring and Regulating Stations Expenses-General			
Labor Adjustments for Existing Headcount	$	13,730	A11
Pension Expense	$	(2,787)	A14
Postretirement Medical Expense	$	940	A15
	$	11,883	
876 Measuring and Regulating Stations Expenses-Industrial			
	$	-	
	$	-	
877 Measuring and Regulating Stations Expenses-City Gate Check Stations			
	$	-	
	$	-	
878 Meter and House Regulator Expenses			
Labor Adjustments for Existing Headcount	$	18,411	A11
Pension Expense	$	(3,737)	A14
Postretirement Medical Expense	$	1,260	A15
	$	15,934	
879 Customer Installation Expenses			
Labor Adjustments for Existing Headcount	$	320,079	A11
Pension Expense	$	(64,961)	A14
Postretirement Medical Expense	$	21,913	A15
	$	277,031	
880 Other Expenses			
Labor Adjustments for Existing Headcount	$	155,914	A11
Pension Expense	$	(31,643)	A14
Postretirement Medical Expense	$	10,674	A15
Training Expense	$	363,944	A16
Additional Employees	$	44,335	A17
Aging Workforce	$	363,140	A19
Distribution Maintenance	$	35,310	A23
Changes in Cost Allocations	$	(320)	A37
	$	941,354	
881 Rents			
	$	-	
	$	-	
885 Maintenance Supervision and Engineering			
Labor Adjustments for Existing Headcount	$	46,577	A11
Pension Expense	$	(9,453)	A14
Postretirement Medical Expense	$	3,189	A15
	$	40,313	
886 Maintenance of Structures and Improvements			
Labor Adjustments for Existing Headcount	$	4,787	A11
Pension Expense	$	(972)	A14
Postretirement Medical Expense	$	328	A15
Regulator Station Maintenance	$	1,253,218	A24
	$	1,257,361	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

887 Maintenance of Mains			
Labor Adjustments for Existing Headcount	$	75,029	A11
Pension Expense	$	(15,227)	A14
Postretirement Medical Expense	$	5,136	A15
Additional Employees	$	149,788	A17
	$	214,726	
888 Maintenance of Compressor Station Equipment			
Labor Adjustments for Existing Headcount	$	21	A11
Pension Expense	$	(4)	A14
Postretirement Medical Expense	$	1	A15
	$	18	
889 Maintenance of Measuring and Regulating Station Equipment-General			
Labor Adjustments for Existing Headcount	$	6,367	A11
Pension Expense	$	(1,292)	A14
Postretirement Medical Expense	$	436	A15
	$	5,511	
890 Maintenance of Meas. & Reg. Station Equipment-Industrial			
	$	-	
	$	-	
891 Maintenance of Meas. & Reg. Station Equipment-City Gate Check Stations			
	$	-	
	$	-	
892 Maintenance of Services			
Labor Adjustments for Existing Headcount	$	63,608	A11
Pension Expense	$	(12,909)	A14
Postretirement Medical Expense	$	4,355	A15
Changes in Cost Allocations	$	(1,821)	A37
	$	53,233	
893 Maintenance of Meters and House Regulators			
Labor Adjustments for Existing Headcount	$	2,758	A11
Pension Expense	$	(560)	A14
Postretirement Medical Expense	$	189	A15
Meter Maintenance Expense	$	1,275,212	A25
	$	1,277,599	
894 Maintenance of Other Equipment			
Labor Adjustments for Existing Headcount	$	3,880	A11
Pension Expense	$	(787)	A14
Postretirement Medical Expense	$	266	A15
	$	3,359	
901 Supervision (Customer Accounts)			
Labor Adjustments for Existing Headcount	$	51,638	A11
Pension Expense	$	(10,480)	A14
Postretirement Medical Expense	$	3,535	A15
Additional Employees	$	278,424	A17
	$	323,117	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

902 Meter Reading Expenses			
Labor Adjustments for Existing Headcount	$	27,425	A11
Pension Expense	$	(5,566)	A14
Postretirement Medical Expense	$	1,878	A15
Additional Employees	$	39,000	A17
Miscellaneous Billing Expense	$	109,290	A27
	$	172,027	
903 Customer Records and Collection			
Labor Adjustments for Existing Headcount	$	302,297	A11
Pension Expense	$	(61,352)	A14
Postretirement Medical Expense	$	20,694	A15
Additional Employees	$	199,042	A17
Miscellaneous Billing Expense	$	112,700	A27
Contact Center Costs	$	(194,367)	A28
	$	379,014	
904 Uncollectible Accounts			
Uncollectible Accounts Expense	$	(68,533)	A26
	$	(68,533)	
905 Miscellaneous Customer Accounts			
Labor Adjustments for Existing Headcount	$	13,764	A11
Pension Expense	$	(2,793)	A14
Postretirement Medical Expense	$	942	A15
	$	11,913	
907 Supervision (Customer Service)			
	$	-	
	$	-	
908 Customer Assistance Expenses			
Labor Adjustments for Existing Headcount	$	17,798	A11
Pension Expense	$	(3,612)	A14
Postretirement Medical Expense	$	1,218	A15
	$	15,404	
909 Informational and Instructional Expenses			
Additional Employees	$	30,576	A17
Safety Communication Costs	$	719,424	A29
	$	750,000	
910 Miscellaneous Customer Service and Informational			
Labor Adjustments for Existing Headcount	$	5,575	A11
Pension Expense	$	(1,132)	A14
Postretirement Medical Expense	$	382	A15
	$	4,825	
911 Supervision (Sales)			
Labor Adjustments for Existing Headcount	$	222	A11
Pension Expense	$	(45)	A14
Postretirement Medical Expense	$	15	A15
	$	192	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

912 Demonstrating and Selling Expenses			
Labor Adjustments for Existing Headcount	$	9,491	A11
Pension Expense	$	(1,926)	A14
Postretirement Medical Expense	$	650	A15
Additional Employees	$	295,058	A17
Economic Development Expense	$	288,263	A30
	$	591,536	
913 Advertising Expenses			
Energy Efficiency Funding Costs	$	2,260,979	A21
	$	2,260,979	
916 Miscellaneous Sales Expenses			
	$	-	
	$	-	
920 Administrative and General Salaries			
Labor Adjustments for Existing Headcount	$	362,636	A11
Other Compensation	$	1,101,812	A13
Pension Expense	$	(73,598)	A14
Postretirement Medical Expense	$	24,825	A15
Additional Employees	$	627,122	A17
	$	2,042,797	
921 Office Supplies and Expenses			
Labor Adjustments for Existing Headcount	$	5,403	A11
Pension Expense	$	(1,097)	A14
Postretirement Medical Expense	$	370	A15
Human Resource Programs	$	183,750	A18
Information Technology Costs	$	428,724	A31
Other Cost Reductions	$	(427,956)	A36
Changes in Cost Allocations	$	(185,922)	A37
	$	3,272	
922 Administrative Expenses Transferred-Credit			
	$	-	
	$	-	
923 Outside Services Employed			
Labor Adjustments for Existing Headcount	$	651	A11
Pension Expense	$	(132)	A14
Postretirement Medical Expense	$	45	A15
Energy Efficiency Funding Costs	$	794,399	A21
Changes in Cost Allocations	$	139,088	A37
Asset Charge	$	478,466	A39
	$	1,412,517	
924 Property Insurance			
Property and Risk Insurance	$	(27,483)	A34
	$	(27,483)	

VECTREN NORTH
ADJUSMENT SUMMARY - O&M
FOR THE TWELVE MONTH PERIOD ENDING DECEMBER 31, 2006

925 Injuries and Damages			
Property and Risk Insurance	$	(87,575)	A34
Claims Expense	$	650,642	A35
	$	563,067	
926 Employee Pensions and Benefits			
	$	-	
	$	-	
928 Regulatory Commission Expenses			
Rate Case Expense	$	120,589	A32
IURC Fee	$	119,803	A38
	$	240,392	
930.1 General Advertising Expenses			
	$	-	
	$	-	
930.2 Miscellaneous General Expenses			
Labor-Related Costs	$	692,344	A12
Changes in Cost Allocations	$	(22,560)	A37
	$	669,784	
931 Rents			
Changes in Cost Allocations	$	(25,113)	A37
	$	(25,113)	
932 Maintenance of General Plant			
Labor Adjustments for Existing Headcount	$	21,137	A11
Pension Expense	$	(4,290)	A14
Postretirement Medical Expense	$	1,447	A15
	$	18,294	
Operations and Maintenance Adjustments	**$**	**20,299,543**	
403 Depreciation Expense			
Depreciation and Amortization	$	1,977,581	A40
	$	1,977,581	
403.1 Depr Exp for Asset Retirement Costs			
	$	-	
	$	-	
407.4 Amortization of Regulatory Assets			
	$	-	
	$	-	
Depreciation and Amortization Adjustments	**$**	**1,977,581**	
408.1 Taxes Other than Income Taxes			
Indiana Utility Receipts Tax	$	691,550	A43
Property Tax Expense	$	551,763	A44
	$	1,243,313	
Other Taxes Adjustments	**$**	**1,243,313**	

VECTREN NORTH
BALANCE SHEET
AS OF DECEMBER 31, 2006

(In Thousands)

	ASSETS		December 2006		December 2005
1	CURRENT ASSETS:				
2	Cash and cash equivalents	$	2,653	$	5,609
3	Customer accounts receivable, less reserves		57,475		72,209
4	Accounts receivable from affiliated companies		769		-
5	Accounts receivable from other Vectren companies		6,051		551
6	Accrued unbilled revenues		65,322		121,462
7	Materials and supplies - at average cost		2,175		2,691
8	Liquedfied petroleum gas - at average cost		777		789
9	Gas in underground storage - at last-in, first-out cost		14,333		11,338
10	Recoverable fuel and natural gas costs		-		4,953
11	Prepaid gas delivery service		66,235		69,330
12	Prepayments and other current assets		4,230		10,172
13		$	220,020	$	299,104
14	UTILITY PLANT:				
15	Original cost	$	1,244,413	$	1,223,464
16	Completed construction not classified		67,929		38,770
17	Utility plant held for future use		444		444
18	Gas stored - base gas		8,581		8,581
19	Construction work in progress		26,021		29,083
20	Less - Accumulated depreciation and amortization		481,072		451,038
21		$	866,316	$	849,304
22	NONUTILITY PLANT AND OTHER INVESTMENTS				
23	Nonutility Property, Net	$	51	$	101
24	Investment in VEDO		231,821		226,249
25	Other Investments		5,699		5,538
26		$	237,571	$	231,888
27	DEFERRED CHARGES:				
28	Unamortized debt expense and premium	$	8,659	$	9,768
29	Accumulated deferred income tax		8,211		7,832
30	Other Regulatory assets		5,960		2,363
31	Miscellaneous Deferred Debits		8,379		5,380
32		$	31,209	$	25,343
33	Total Assets	$	1,355,116	$	1,405,639

VECTREN NORTH
BALANCE SHEET
AS OF DECEMBER 31, 2006

(In Thousands)

	LIABILITIES AND SHAREHOLDER'S EQUITY	December 2006	December 2005
1	CURRENT LIABILITIES:		
2	Accounts payable	$ 41,656	$ 28,424
3	Accounts payable to affiliated companies	56,362	117,189
4	Payables to other Vectren companies	2,510	7,749
5	Customer deposits and advance payments	22,146	17,008
6	Accrued taxes	9,074	10,557
7	Accrued interest	3,648	2,957
8	Current deferred income taxes	-	2,055
9	Other current liabilities	19,117	23,723
10	Intercompany accrued interest	1,641	1,594
11	Short-term borrowings to VUHI	66,626	162,845
12	Long-term debt subject to tender	20,000	-
13	Current maturities of long-term debt	6,500	-
14	Refundable gas costs	26,052	-
15		$ 275,332	$ 374,101
16	DEFERRED CREDITS:		
17	Regulatory Liabilities	$ 152,801	$ 142,994
18	Deferred income taxes	81,242	81,980
19	Accrued postretirement benefits other than pensions	10,052	14,539
20	Investment tax credit - net	1,817	2,632
21	Other	21,753	18,861
22		$ 267,665	$ 261,006
23	CAPITALIZATION:		
24	Common stock	$ 367,995	$ 367,995
25	Retained earnings	99,286	90,600
26	Common shareholder's equity	$ 467,281	$ 458,595
27	Notes payable	101,000	127,500
28	Long-term borrowings with VUHI	243,838	184,437
29		$ 812,119	$ 770,532
30	Total Liabilities and Shareholder's Equity	$ 1,355,116	$ 1,405,639

VECTREN NORTH
INCOME STATEMENT
AS OF DECEMBER 31, 2006

(In Thousands)		12 Months December 2006	12 Months December 2005
1	GAS		
2	Sales	$ 712,917	$ 805,702
3	Transportation	26,244	26,039
4	TOTAL GAS REVENUE	$ 739,161	$ 831,741
5	Cost of gas sold	503,025	595,940
6	MARGIN ON GAS OPERATIONS	$ 236,136	$ 235,801
7	OPERATING EXPENSES:		
8	Other operation	$ 84,539	$ 84,833
9	Maintenance	9,725	9,929
10	Depreciation and amortization	48,457	46,778
11	Income taxes	14,942	17,088
12	Taxes other than income taxes	20,276	21,616
13		$ 177,939	$ 180,244
14	OPERATING INCOME	$ 58,197	$ 55,557
15	OTHER INCOME (EXPENSE):		
16	AFUDC - equity	$ (4)	$ 73
17	AFUDC - debt	762	231
18	Other - net	(1,621)	(1,204)
19	Equity in VEDO	5,572	5,470
20		$ 4,709	$ 4,570
21	INCOME (LOSS) BEFORE INTEREST AND OTHER CHARGES	$ 62,906	$ 60,127
22	INTEREST AND OTHER CHARGES:		
23	Interest on long-term debt	$ 8,499	$ 11,845
24	Interest on VUHI borrowings	18,071	14,170
25	Amortization of premium	1,113	1,109
26	Other interest on short-term borrowings	1,182	662
27		$ 28,865	$ 27,786
28	NET INCOME	$ 34,041	$ 32,341

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

IURC CAUSE NO. 43298

DIRECT TESTIMONY
OF
PAUL R. MOUL

ON

COST OF EQUITY
FAIR RATE OF RETURN ON FAIR VALUE

SPONSORING PETITIONER'S EXHIBITS PRM-1 and PRM-2

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FFO	Funds from Operations
FOMC	Federal Open Market Committee
g	Growth rate
GDP	Gross Domestic Product
IGF	Internally Generated Funds
IURC	Indiana Utility Regulatory Commission
Lev	Leverage modification
LT	Long Term
MLP	Master Limited Partnerships
MM	Modigliani and Miller
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	represents the value that accrues to existing shareholders from selling stock at a price different from book value

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

Direct Testimony of Paul R. Moul

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return that the Indiana Utility Regulatory Commission ("IURC" or the "Commission") should allow Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North" or the "Company") an opportunity to earn on its gas jurisdictional rate base devoted to public service. I will also address the fair rate of return applicable to the Company's fair value rate base. My analysis and recommendation are supported by the detailed financial data contained in Petitioner's Exhibit No. PRM-2, which is a multi-page document divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely. My testimony is based upon my first hand knowledge of Vectren North consisting of information obtained from meetings with the Company's management and Company-specific data, which is widely disseminated within the financial community.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.50%. As shown on Schedule 1, I have presented the weighted average cost of capital for the Company, as taken from the pre-filed direct testimony of Mr. Robert L. Goocher, the Company's Vice President and Treasurer. Calculations are also provided that include capital from non-investor provided sources typically used in the ratesetting process by the IURC. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and provides the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of Vectren Utility Holdings, Inc. ("VUHI"), which in turn is a wholly-owned subsidiary of Vectren Corporation ("Vectren"). The common stock of Vectren is traded on the New York Stock Exchange. Vectren is a component of the S&P 400 Midcap Index.

The Company provides natural gas distribution service to over 565,000 customers located in central and southern Indiana. Throughput to these customers in 2006 was represented by approximately 36% to residential customers, approximately 17% to commercial customers, and approximately 47% to industrial customers. Industrial customers comprise just 849 customers, or less than one-quarter of one percent of the Company's customers. This means that the energy needs of a few customers can have a significant impact on the Company's operations.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as Vectren North. In this regard, I relied on four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

Q. In your opinion, what factors should the Commission consider when determining

the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of eight natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) have not recently cut or omitted their dividend, (v) are not currently the target of a merger or acquisition, (vi) operate with a weather normalization and/or decoupling feature to their tariff or have other similar features, and (vii) have at least 70% of their assets subject to utility regulation. As my selection criteria included companies in the basic service of Value Line, very small companies were not considered, because they typically are found in the expanded service of Value Line. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony. These are also the same companies that I utilized as the proxy group in the pending Vectren South-Gas rate case in Cause No. 43112.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	9.85%
RP	11.69%
CAPM	12.71%
Comparable Earnings	14.20%
Average	12.11%
Median	12.20%
Mid-point	12.03%

Focusing upon the market model approaches of the cost of equity (i.e., DCF, RP and CAPM), the average equity return is 11.42% (9.85% + 11.69% + 12.71% = 34.25% ÷ 3). From all these measures, I recommend that the Commission set the Company's rate of return on common equity at 11.50%. The specific factors that impact the Company's risk profile is described in the following section of my testimony, and in the pre-filed direct testimony of Mr. Jerome A. Benkert, Jr., the Company's Executive Vice President and Chief Financial Officer. My cost of equity of 11.50% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events.

I should note that at this time, the DCF model is providing atypical results. That is to say, the low DCF returns can be traced in part to the unfavorable investor sentiment for the gas companies. This is shown by the average Value Line Timeliness Rank for my Gas Group, which is "4" and places them in the below average category and signifies that they are relatively unattractive investments. Moreover, page 5 of Schedule 11 shows that the gas distribution companies are ranked 85 out of 96 industries for probable performance over the next twelve months. The significance of this low ranking is that performance for this group is expected to be subpar, thereby indicating that the DCF results will not provide a cost of equity indication that corresponds with the results of the other methods/models. Although I have not ignored the DCF results, I am recommending less reliance on DCF in this case.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. The new competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCA mechanism. Higher and volatile gas costs may result in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. While improved rate design can mitigate the impact of declining average use for small customers, the loss of load due to conservation, fuel switching or plant closures cannot be mitigated for large customers. The resulting high gas prices have also had an impact on the amount of and number of delinquent customer accounts.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end-users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. Does the Company face competition in its natural gas business?

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as Vectren North, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

Q. How does the Company's throughput to industrial customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. The throughput to the Company's industrial customers represents 47% of total throughput, although this class contains only 849 customers. Large volume users, which have traditionally used transportation service, also have the ability to bypass the Company' system. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory. Indiana has a significant amount of traditional manufacturing. As these firms leave the State in search of cheaper labor, or go out of business, load can be lost for large customers, as well as the out-migration of high paying jobs associated with these customers. This puts fixed cost recovery at risk. Some of that loss can be offset by economic growth, but the Company faces potential net negative growth and lost margins. This differs from other areas of the country where LDC's still experience steady organic growth. The Company serves many rural areas and small to mid-size communities throughout the State. Its service territory is particularly vulnerable to these economic realities in cities such as Marion and Anderson where they struggle to attract new types of businesses and rebound from the loss of traditional employers long served by the Company.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company had 1,052 miles of its distribution mains constructed of cast iron, ductile iron, and unprotected steel pipe as of year-end 2006. Also, the Company has 23,321 of its services constructed of unprotected steel. The Company projects its construction expenditures will be approximately $358 million in the period 2007-2011.

Over this five-year period, these capital expenditures will represent approximately 51% ($358 million ÷ $704 million) of the net utility plant (excluding cushion gas) of the Company's original cost rate base included in this proceeding.

Q. Does your cost of equity analysis and recommendation take into account the revenue decoupling and normal temperature adjustment ("NTA") riders that now exists for the Company?

A. Yes. Among other riders in the Company's existing tariff, the revenue decoupling and NTA are intended to separate revenues from variations in sales related to usage caused by variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in a test year context and by conservation efforts by the Company's customers. My cost of equity analysis that provides an 11.50% rate of return on common equity takes into account the Company's existing and proposed riders.

Q. Do the LDCs included in your Gas Group already have tariff mechanisms similar to decoupling and the NTA?

A. Yes, and therefore my analysis already reflects the impacts of the decoupling and NTA on investor expectations through the use of market-determined models. The companies in my Gas Group already have some form of revenue stabilization mechanism, most of which are related to temperature variations, and one company has a weather mitigation rate design intended to deal with the effect of weather volatility during the months of December through May. As such, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust revenues for abnormal weather, conservation, and other items. The trend in the industry is to stabilize the recovery of fixed costs which are unaffected by usage. Indeed, there has been a proliferation of tracking mechanisms in the LDC business. The Company's decoupling and NTA are designed to help to achieve the same goals that other LDCs already have in place.

Q. How do investors assess the risk to an LDC of variations in customer usage caused by weather?

A. Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a NTA.

That is not to say there are no benefits to decoupling and NTA. Variations in weather can significantly affect customers' bills and the Company's cash flow. Fluctuations in bad debt expense from year to year, which may also be driven in part by variations in weather, also affect the Company's cash flow. Therefore, the Company can be expected to realize a short-term benefit of improved or at least more predictable liquidity as a result of these riders. Indeed, the decoupling and NTA removes some of the Company's cash flow variability, which would be viewed favorably by the credit rating agencies. As such, the decoupling and NTA would help the Company to sustain its credit ratings. These are beneficial impacts which will be most directly manifested at the credit quality level rather than the determination of the Company's cost of equity.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular Vectren North?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to the risk related to earnings attrition even with decoupling, since other costs are rising each year but margins are flat with minor customer growth. This leaves the Company in the situation that its ability to earn the allowed return is in jeopardy even with decoupling.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk already have been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and its required returns are described in Appendix B. For this purpose, I have utilized the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and the Gas Group.

Q. What are the components of the S&P public utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of utility companies.

Q. What criteria did you employ to assemble the Gas Group?

A. I previously enumerated the criteria that I employed to assemble the Gas Group.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the credit rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. Presently, the corporate credit rating ("CCR") for Vectren North is A- from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is Baa1 from Moody's Investors Services ("Moody's"). The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Gas Group is an A from S&P and A3 from Moody's. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for Vectren North, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2001-2005. Complete 2006 data is not presently available from S&P Utility Compustat, which is the database used for Schedules 2, 3, and 4. For the purpose of my analysis, I have analyzed the historical results for Vectren North, the Gas Group and the S&P Public Utilities. I will highlight the important categories of relative risk as follows:

Size. In terms of capitalization, Vectren North is approximately one-half the average size of the Gas Group. The S&P Public Utilities are many times the size of Vectren North and the Gas Group. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Vectren North and the Gas Group.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for Vectren North because its stock is owned by Vectren. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was higher for the Gas Group, as compared to the S&P Public Utilities. The five-year average market-to-book ratio was higher for the Gas Group, as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 51.0% for Vectren North, 51.0% for the Gas Group and 39.5% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.366 (2.6% ÷ 7.1%) for Vectren North, 0.067 (0.8% ÷ 12.0%) for the Gas Group, and 0.231 (2.5% ÷ 10.8%) for the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 90.0% for Vectren North, 88.1% for the Gas Group, and 84.6% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 2.28

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[1] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

times for Vectren North, 3.90 times for the Gas Group, and 2.68 times for the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for Vectren North, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 110.2% for Vectren North, 90.7% for the Gas Group, and 109.0% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas provided on page 2 of Schedule 3 -- .81 as the average for the Gas Group, and page 3 of Schedule 4 -- .95 as the average for the S&P Public Utilities.

Q. Please summarize your risk evaluation of Vectren North and the Gas Group.

A. Vectren North is smaller than the average size of the Gas Group, it has lower and more variable rates of return on common equity, and its interest coverage is lower. Not surprisingly, its credit ratings are weaker than the Gas Group. Further, the Company has a substantial portion of its throughput to industrial customers. Overall, the fundamental risk factors indicate that the Gas Group provides a conservative basis for measuring the Company's cost of equity.

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[3] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix I. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships between Vectren North, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix C. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity indicated by the models.

It also is important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix C, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and have arrived at a cost of equity of 11.50% for Vectren North.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix D. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix D, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to book value, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value. This is to say, such distortions tend to produce DCF results that understate the cost of equity to the regulated firm when using book values.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended March 2007, the monthly dividend yields of the Gas Group are shown graphically on Schedule 5. The monthly dividend yields shown on Schedule 5 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix D.

For the twelve months ending March 2007, the average dividend yield was 3.81% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.72% and 3.78%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.72% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs, while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix D. That adjusted dividend yield is 3.83% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of its investment (i.e., the price per share of the stock). As I explain in Appendix D, future earnings per share growth represents its primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis also can be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing its capital gains expectations with its dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, high fuel costs, and environmental costs are worked-out in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by fluctuations in operating expenses and capital costs.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in The Wall Street Journal, The New York Times, Fortune, Forbes, and Business Week. Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the October 10, 2006 issue of Blue Chip, those forecasts are:

Blue Chip Economic Indicators		
Averages	Nominal GDP	Corporate Profits, Pretax
2008-12	5.2%	5.4%
2013-17	5.1%	5.8%

These forecasts show that growth in corporate profits generally will exceed growth in overall GDP. It also is indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[4]

Q. What company-specific data have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 6 and 7. The bar graph provided on Schedule 6 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these

[4] Obviously, growth in corporate profits is negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since 1934.

data. As shown on Schedule 6, historical growth in earnings per share was in the range of 5.00% to 8.19% for the Gas Group.

Schedule 7 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 7 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?

A. Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 7 indicates that the projected earnings per share growth rates for the Gas Group are 4.74% by IBES/First Call, 5.23% by Zacks, 4.72% by Reuters/Market Guide, and 4.19% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 4.19%) than the dividends per share (i.e., 3.44%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix D, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data?

A. Ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm; however, the circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth.[5] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represent a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks,

[5] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, spring 1989 by Gordon, Gordon & Gould.

Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company Act ("PUHCA"), merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell its shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth, as shown on Schedule 7 provide a range of growth rates of 4.74% to 5.23%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As I previously indicated, the restructuring and consolidation now taking place in the utility industry will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts and will enhance the growth prospects for the future. As such, a 5.25% growth rate will accommodate all these factors.

Q. Does the sum of the dividend yield and growth rate provide a complete representation of the cost of equity?

A. No.

Q. Please explain why.

A. As demonstrated in Appendix D, the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity account measured at book value, which is the measure used in calculating the weighted average cost of capital. This is the situation today, where the market price of stock exceeds its book value for most utilities. This divergence of price and book value creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and use those results in computing the weighted average cost of capital with a book value capital structure, those results will not reflect the degree of financial risk associated with the capital structure shown by the market capitalization. This shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity upward to make the return consistent with the book value capital structure.

- January 10, 2002 for Pennsylvania-American Water Company in Docket No. R-00016339 -- 60 basis points adjustment.

- August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750 -- 80 basis points adjustment.

- January 29, 2004 for Pennsylvania-American Water Company in Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004) -- 60 basis points adjustment.

- August 5, 2004 for Aqua Pennsylvania, Inc. in Docket No. R-00038805 -- 60 basis points adjustment.

- December 22, 2004 for PPL Electric Utilities Corporation in Docket No. R-00049255 -- 45 basis points.

- February 8, 2007 for PPL Gas Utilities Corporation in Docket No. R-00061398 -- 70 basis points adjustment.

It must be recognized that in order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification. As I will explain later in my testimony, the DCF model can be modified to account for differences in risk attributed to changes in financial leverage when market prices and book values diverge.

Q. Is your leverage adjustment dependent upon the market valuation or book valuation from an investor's perspective?

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P+g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilizes the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Since the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature.

Q. Are there specific factors that influence market-to-book ratios that determine

whether the leverage adjustment should be made?

A. No. My leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. My leverage adjustment deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment.

Further, as noted previously, the high market prices of gas utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from its cost of equity. Stock prices above book value are common for utility stocks, and indeed non-regulated stock prices exceed book values by even greater margins. In this regard, according to the Barron's issue of April 2, 2007, the major market indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of 2.87 times book value which is below the market multiple of other indices. For example, the S&P 500 index trades at 3.14 times book value, the S&P Industrial index is at 3.59 times book value, and the Dow Jones Industrial index is at 3.52 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of its cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's capitalization?

A. The capital structure ratios measured at the utility's book value show more financial leverage, and higher risk, than the capitalization measured at its market values. Please refer to Appendix D for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Gas Group that is related to the 53.94% common equity ratio using book value has higher financial risk than the 67.54% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Nobel laureates Modigliani and Miller[6] developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that, as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.58% (9.66% - 9.08%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1 /P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used

[6] Modigliani, F. and Miller, M.H. "The Cost of Capital, Corporation Finance, and the Theory of Investments." American Economic Review, June 1958, 261-297.

Modigliani, F. and Miller, M. H. "Taxes and the Cost of Capital: A Correction." American Economic Review, June 1963, 433-443.

in conjunction with the growth rate ("g ") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot.").

Q. Aside from the evidence on flotation application to utilities generally, what has been the experience for the Company?

A. The factor used to develop the modification that would account for the flotation costs adjustment is provided in Schedule 8 and Appendix E. In addition, Vectren Corporation, on behalf of its subsidiaries including Vectren North, have issued stock directly to the public and has incurred flotation costs. Details regarding the 2001, 2003 and 2007 common stock issues by Vectren are shown below:

Date of Offering	2/8/2001	Percent of Offering	8/7/2003	Percent of Offering	2/22/2007	Percent of Offering
No. of shares offered (000)	5,500		6,500		4,600	
Dollar amt. of offering ($000)	$ 116,985		$ 148,265		$ 130,318	
Price to public	$ 21.270		$ 22.810		$ 28.330	
Underwriter's discounts and commission	$ 0.740	3.5%	$ 0.798	3.5%	$ 0.990	3.5%
Gross Proceeds	$ 20.530		$ 22.012		$ 27.340	
Estimated company issuance expenses	$ 0.077	0.4%	$ 0.046	0.2%	$ 0.092	0.3%
Net proceeds to company per share	$ 20.453	3.9%	$ 21.966	3.7%	$ 27.248	3.8%

From the data shown above, the actual experience for stock sales by Vectren shows that flotation costs represent 3.7% to 3.9% of the offering price to the public. Therefore, a flotation costs adjustment must be applied to the DCF result (i.e., "k") that provides an additional increment to the rate of return on equity (i.e., "K").

Q. What DCF cost rate have you calculated?

A. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	$lev.$	=	k	x	$flot.$	=	K
Gas Group	3.83%	+	5.25%	+	0.58%	=	9.66%	x	1.02	=	9.85%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.19% (9.85% - 9.66%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix E. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. As with other models of the cost of equity, the Risk Premium approach has its limitations, including an accurate assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 6.25% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 9. For the twelve months ended February 2007, the average monthly yield on Moody's A-rated index of public utility bonds was 6.09%. For the six and three-month periods ended February 2007, the yields were 5.91% and 5.89%, respectively. During the twelve-months ended February 2007, the range of the yields on A-rated public utility bonds was 5.80% to 6.42%.

Q. What are the implications of emphasizing recent data taken from a period of relatively low interest rates?

A. When interest rates rise from its current low levels, the overall cost of capital and cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates.

The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy. In the two year period between June 2004 and June 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions, which have brought the Fed Funds rate to 5.25%, are widely interpreted as part of the process of moving toward a more neutral range for monetary policy. Current interest rates are characterized by a relatively flat to slightly inverted yield curve, which has endured longer than would have been expected.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix G. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on April 1, 2007, and the yield spread of 1.00% that I describe in Appendix G and Schedule 9. For comparative purposes, I also have shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2007	Second	5.5%	6.4%	4.8%	1.0%	5.8%
2007	Third	5.6%	6.5%	4.9%	1.0%	5.9%
2007	Fourth	5.6%	6.6%	4.9%	1.0%	5.9%
2008	First	5.7%	6.6%	5.0%	1.0%	6.0%
2008	Second	5.7%	6.7%	5.0%	1.0%	6.0%
2008	Third	5.8%	6.7%	5.0%	1.0%	6.0%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2006 publication, the Blue Chip published forecasts of interest rates are reported to be:

	Blue Chip Financial Forecasts				
	Corporate		30-Year	A-rated Public Utility	
Averages	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2008-12	6.1%	7.0%	5.4%	1.0%	6.4%
2013-17	6.3%	7.1%	5.5%	1.0%	6.5%

Given these forecast interest rates, a 6.25% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities, rather than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 10, the indicated risk premiums for the various time periods analyzed are 5.37% (1928-2006), 6.40% (1952-2006), 5.61% (1974-2006), and 5.83% (1979-2006). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals, and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 10 represents the returns realized through 2006. Second, the selection of the initial year of each period was based upon the events that I described in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 10, the 1928-2006 period provides the lowest indicated risk premium, while the 1952-2006 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.72% (5.61% + 5.83% = 11.44% ÷ 2) is shown from data covering the periods 1974-2006 and 1979-2006. Therefore, 5.72% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.25% represents a reasonable common equity risk premium in this case. This represents approximately 92% (5.25% ÷ 5.72% = 0.92) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot."). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	6.25%	+	5.25%	=	11.50%	+	0.19%	=	11.69%

<u>CAPITAL ASSET PRICING MODEL</u>

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. Yes, I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 11, the average beta is .81 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values using the Hamada formula.[7] This adjustment has been made

[7] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452

with the formula:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at its market values, the beta would become .62 for the Gas Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of .97 for the Gas Group associated with book value capital structure. The betas and their corresponding common equity ratios are:

Market Values		Book Values	
Beta	Common Equity Ratio	Beta	Common Equity Ratio
0.81	67.54%	0.97	53.94%

The leveraged beta that I will employ in the CAPM cost of equity is .97 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. For reasons explained in Appendix F, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 11, I provided the historical yields on Treasury notes and bonds. For the twelve months ended February 2007, the average yield was 5.03%, as shown on page 3 of that schedule. For the six- and three-months ended February 2007, the yields on 20-year Treasury bonds were 4.89% and 4.89%, respectively. During the twelve-months ended February 2007, the range of the yields on 20-year Treasury bonds was 4.78% to 5.35%. As shown on page 4 of Schedule 11, forecasts published by Blue Chip on April 1, 2007 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.8% to 5.0% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.4% from 2008 through 2012 and 5.5% from 2013 to 2017. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 5.25% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the CAPM?

A. As developed in Appendix H, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 6.48%). For the historically based market premium, I have used the arithmetic mean. I am aware that the Commission has expressed its preference for considering both the arithmetic mean and the geometric mean. So if that approach is to be taken, much more weight should be placed on the arithmetic mean because it is the correct measure in the single-period model specification of the CAPM. The resulting market premium is 6.49% (6.5% + 6.48% = 12.98% ÷ 2), which represents the average market premium using historical and forecast data.

Q. Are there adjustments to the CAPM results that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. There would be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk and, hence, its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see <u>Fundamentals of Financial Management</u>, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; <u>The Journal of Finance</u>, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in <u>Public Utility Fortnightly</u>, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the <u>SBBI Yearbook</u> that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, Gas Group has an average market capitalization of its equity of $1,638 million, which would make them a low cap portfolio. The low cap market capitalization would indicate a size premium of 1.76%. Absent such an adjustment, the CAPM would understate the required return. However, for my CAPM analysis, I have adopted a size adjustment of 0.97%, which represents the mid-cap adjustment, and is conservative because the market capitalization of Vectren North by itself would be smaller than either the mid-cap or low-cap category.

Q. What CAPM result have you determined using the CAPM?

A. Using the 5.25% risk-free rate of return, the leverage adjusted beta of .97 for the Gas Group, the 6.49% market premium, the size adjustments, and the flotation cost adjustment developed previously, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*	+	*flot.*	=	*K*
Gas Group	5.25%	+	0.97	x (	6.49%	) +	0.97%	=	12.52%	+	0.19%	=	12.71%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved, or expected to be achieved, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the current risk profile of the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships (MLPs).

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of the companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Schedule 12.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 12, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because, the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 14.9% using the median value as shown on page 2 of Schedule 12. The forecast rates of return, as published by Value Line are shown by the 13.5% median values also provided on page 2 of Schedule 12.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

	Historical	*Forecast*	*Average*
Comparable Earnings Group	14.90%	13.50%	14.20%

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion concerning the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is 11.50% for the Company. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

FAIR RATE OF RETURN ON FAIR VALUE

Q. Have you also considered what would represent a fair return on the fair value of the Company's property?

A. Yes. Indiana ratesetting principles require that rates provide the utility with an opportunity to earn a fair rate of return on the fair value of its property used to provide utility service. Therefore, I have also performed a fair value analysis.

Q. In your opinion, what would be an appropriate fair value rate base for the Company?

A. In my opinion, it would be appropriate to give weight to both the replacement cost new less depreciation ("Replacement Cost") and the original cost less depreciation ("Original Cost") of the Company's utility property. In particular, I have derived a weighted fair value rate base by giving 48.99% weight to Replacement Cost and 51.01% weight to Original Cost. These relative weights were determined from the capital structure ratios calculated by Vectren North Witness Robert L. Goocher, as shown on page 1 of Petitioner's Exhibit RLG-2. The 48.99% weight assigned to the Replacement Cost value represents the Company's common equity ratio. The weight assigned to the Original Cost value represents the remaining components of the Company's ratesetting capital structure. This method represents a compromise approach that is intended to make sure that, at a minimum, the Company gets the benefit of the appreciation in value of its assets to the extent they were financed by the common equity investor.

Q. What amount did you use for the Replacement Cost of the property?

A. My starting point was the replacement cost less depreciation valuation of the Company's utility plant in service as of December 31, 2006 performed by Vectren North Witness John P. Kelly. Mr. Kelly states in his testimony that his methodology gives consideration to current construction costs technology. In order to make sure the effect of technological change on replacement costs was not understated, I asked Mr. Kelly to make an additional downward adjustment of 2.1% per year to the depreciable plant. This resulted in an adjusted Replacement Cost value of $915,062,057 as shown on page 1 of Petitioner's Exhibit JPK-3. I then added $8,400,000 for Greenscastle 12" transmission line, $25,800,000 for Greensburg pipeline upgrade, $8,581,320 for cushion gas, and $77,129,060 of materials and supplies, which includes liquefied petroleum gas, utility material and supplies, store expense, gas in underground storage, and prepaid gas delivery, that are included in the Company's proposed Original Cost rate base (Petitioner's Exhibit No. MSH-3, page 2 of Adjustment A45)) but which were not included in Mr. Kelly's valuation. This resulted in a total Replacement Cost rate base of $1,034,972,437.

Q. Why did you recommend a technology adjustment of 2.1%?

A. Mr. Kelly advised me that the average age of the current cost dollars invested in the Company's gas plant was approximately 25 years. In my opinion, a reasonable adjustment for technological change would reflect productivity advances over that period of time (1981 to 2006). The Bureau of Labor Statistics ("BLS") index of labor productivity (output per hour worked) provides the basis for calculating the following measures of productivity over this time frame:

Bureau of Labor Statistics
Measures of Productivity
1981 to 2006

Seasonally Adjusted	2.16%
Sector : Nonfarm Business	2.08%
Sector : Nonfinancial Corporations	2.28%

From this information, I concluded that a productivity factor of approximately 2.1% would be a reasonable measure of the impact of technological change.

Q. What amount did you use for the Original Cost of the Company's property?

A. I used the amount of $790,007,009, which is the Original Cost rate base supported by Petitioner's Witness Ms. M. Susan Hardwick as shown on Petitioner's Exhibit No. MSH-3, page 2 of Adjustment A45.

Q. What weighted fair value rate base did you derive from this data?

A. Using the methodology described above, I developed a fair value rate base of $910,015,572 as follows:

Valuation Method	Amount	Weight	Weighted Amount
Replacement Cost	$ 1,034,972,437	48.99%	$ 507,032,997
Original Cost	$ 790,007,009	51.01%	$ 402,982,575
Fair Value		100.00%	$ 910,015,572

Q. In your opinion, what would be a fair rate of return on the fair value of the Company's rate base?

A. As shown by Mr. Kelly's testimony and exhibits, the current value of the Company's rate base exceeds the original cost of these assets. This is due mainly to the inflation that has occurred since the property was devoted to public service. The argument is sometimes made that, if inflation is reflected in a utility's property values, then inflation should be removed from the utility's cost of capital. I have reservations concerning this theory. First, the inflation deduction theory provides a mismatch of the historical inflation reflected in property values and the prospective inflation expectations reflected in capital costs as established by investors. Further, under fair value ratesetting the utility and its equity owners should benefit from the appreciation in the value of the utility's property since its installation date. Reducing the rate of return applicable to the fair value rate base below the cost of capital has the effect of depriving the equity owner of at least some (and potentially all) of this benefit. However, setting aside these concerns, I have calculated a 7.65% rate of return on fair value that reflects the removal of inflation from the common equity cost rate used in the determination of the Company's cost of capital. The rate of return is shown on Schedule 13.

Q. How have you calculated the 7.65% fair rate of return applicable to the fair value rate base?

A. In order to synchronize the historical inflation adjustment with the Company's rate base, I have calculated a 3.24% historical inflation rate covering the years 1981 through 2006. The year 1981 was selected as the initial year because it corresponds to the average age of the current cost dollars invested in the Company's property, plant and equipment measured by Mr. Kelly. As previously discussed, the year 1981 was also used as the starting point for measuring the productivity factor.

As described above, the Replacement Cost rate base receives 48.99% weight in the determination of the Company's fair value rate base for purposes of my analysis. The remaining weight (i.e., 51.01%) has been assigned to the Original Cost rate base. On this basis, therefore, it is necessary to employ these same weights in removing historical inflation from the cost of capital. That is to say, 1.59% (3.24% × .4899) should be removed from the Company's cost of equity in order to provide the same recognition for historical inflation that is reflected in the fair value rate base.

Based upon these considerations, I have reduced the Company's 11.50% cost of equity to 9.91% (11.50% - 1.59%) to reflect the same historical inflation and weight assigned to it in the fair value rate base calculation. As shown on Petitioner's Exhibit PRM-2, Schedule 13, the 9.91% equity rate and Mr. Goocher's capital structure (Petitioner's Exhibit RLG-2, page 1) provides a rate of return of 7.65% applicable to a fair value rate base. In this way, I have synchronized both the amount of historical inflation reflected in the rate base and the weight assigned to current value that was used to develop the fair value rate base. In my opinion, a rate of return of 7.65% on the Company's fair value rate base would be fair and reasonable.

Q. Does this conclude your prepared direct testimony?

A. Yes.

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the

Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding

the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2006	Thirty-eighth Financial Forum	Society of Utility & Regulatory Financial Analysts
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah

October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated

companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the <u>Bluefield</u> decision. The <u>Bluefield</u> decisions requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = \$100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \mathrm{K} + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0 (1 + g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0 (1 + g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, Ks is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

1 Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend *(D_0)* of $0.80, the current price *(P_0)* of $10.00, and the investor expected dividend growth rate *(g)* of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be $17.10 as compared with the price per share of $16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price *(P_0)* of $10.00, a dividend *($D_0$)* of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Schedule 3. The 2001-2005 five-year average dividend yield was 4.5% for the Gas Group. The monthly dividend

yields for the past twelve months are shown graphically on Schedule 5. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.625% (5.25% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be

3.82% (3.72% x 1.02625) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend *(D_0)* is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 3.84% (3.72% x 1.03260) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)*, results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *(D_0)*:

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was

0.9300% (3.72% ÷ 4) for the Gas Group. The compound dividend yield would be 3.82% (1.009420^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 3.83% forward-looking dividend yield is the average (3.82% + 3.84% + 3.82% = 11.48% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage,_(vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are

considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an

[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*BxR*" shown on Schedule 7 Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

Gas Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	32.29%	45.82%
Preferred Stock	0.18	0.25
Common Equity	67.54	53.94
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$8.32\% = 9.08\% - (((8.32\%-5.91\%)\ .65)\ 32.29\%/67.54\%) - (8.32\% - 5.98\%)\ 0.18\%/67.54\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt[3], d = dividend rate on preferred stock[4], D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.32% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 8.32% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$9.66\% = 8.32\% + (((8.32\%-5.91\%).65)\ 45.82\%/53.94\%) + (8.32\%-5.98\%)\ 0.25\%/53.94\%$$

3 The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

4 The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-

income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Schedule 8. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2002 to 2006. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the

financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered

by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower

yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep

> inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy

> works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen

25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. In its March 21, 2007 press release, the FOMC stated:

> "Recent indicators have been mixed and the adjustment in the housing sector is ongoing. Nevertheless, the economy seems likely to continue to expand at a moderate pace over coming quarters.
>
> Recent readings on core inflation have been somewhat elevated. Although inflation pressures seem likely to moderate over time, the high level of resource utilization has the potential to sustain those pressures.
>
> In these circumstances, the Committee's predominant policy concern remains the risk that inflation will fail to moderate as expected. Future policy adjustments will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 9 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank

investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 9. There, it is shown that those spreads were about the one percentage during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 9, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005, and 1.08% in 2006. As shown by the monthly data presented on pages 4 and 5 of Schedule 9, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.06 percentage points for the twelve-months ended February 2007. For the six- and three-month periods ending February 2007, the yield spread was 1.02% and 1.00%, respectively.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 11 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount

> them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a

residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations

for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 10 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way,

the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.86%	5.41%
Geometric Mean	4.25%	3.35%
Median	10.17%	7.29%
Midpoint of Range	7.21%	5.32%
Average	6.54%	5.37%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 10 should also be considered. One of these sub-periods included the 54-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as

Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 10.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\,(Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas

less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient ("β"), the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 11 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the March 30, 2007 edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 11) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of March 30, 2007	1.7%	+	8.78%[1]	=	10.48%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.97%.

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.93%	(	1.05465	)	+	10.93%	=	12.97%

where:					
	Price (P)	at	30-Mar-2007	=	1420.86
	Dividend (D)	for	4th Qtr. '06	=	6.87
	Dividend (D)		annualized	=	27.48
	Growth (g)		First Call EpS	=	10.93%

Using these indicators, the total market return is 11.73% (10.48% + 12.97% = 23.45% ÷ 2) using both the Value Line and S&P derived returns. With the 11.73% forecast market return and the 5.25% risk-free rate of return, a 6.48% (11.73% - 5.25%) market premium would be

[1] The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{.25} - 1$).

indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 11. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 11, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.49% (6.5% + 6.48% = 12.98% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 6.48% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market

fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

IURC CAUSE NO._ 43298

FINANCIAL EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

PAUL R. MOUL

Indiana Gas Company, d/b/a Vectren North

Index of Schedules

Indiana Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc.
Rate of Return Applicable to an Original Cost Rate Base
For the Test Year Ending December 31, 2006

Investor Provided Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.28%	6.86%	3.04%
Common Equity	55.72%	11.50%	6.41%
Total	100.00%		9.45%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 40.525% composite federal and state income tax rate (13.82% ÷ 3.04%)	4.55 x
Post-tax coverage of interest expense (9.45% ÷ 3.04%)	3.11 x

For Ratesetting Purposes	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.93%	6.86%	2.68%
Common Equity	48.99%	11.50%	5.63%
Customer Deposits	2.08%	5.00%	0.10%
Cost-free Capital	9.82%	0.00%	0.00%
JDITC	0.18%	9.45%	0.02%
Total	100.00%		8.43%

Indiana Gas Company, Inc.
Capitalization and Financial Statistics
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 770.5	$ 816.4	$ 856.0	$ 736.6	$ 737.5	
Short-Term Debt	$ 162.8	$ 109.2	$ 64.0	$ 108.2	$ 134.3	
Total Capital	$ 933.4	$ 925.7	$ 920.0	$ 844.7	$ 871.8	
						Average
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	40.5%	44.3%	46.7%	56.3%	57.1%	49.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity (1)	59.5%	55.7%	53.3%	43.7%	42.9%	51.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	50.9%	50.9%	50.4%	61.9%	63.7%	55.6%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity (1)	49.1%	49.1%	49.6%	38.1%	36.3%	44.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	7.1%	5.4%	8.1%	10.8%	4.1%	7.1%
Operating Ratio (2)	91.3%	91.5%	89.3%	86.3%	91.7%	90.0%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	2.78 x	2.20 x	2.64 x	2.44 x	1.41 x	2.29 x
Post-tax: All Interest Charges	2.16 x	1.83 x	2.08 x	2.06 x	1.32 x	1.89 x
Overall Coverage: All Int. & Pfd. Div.	2.16 x	1.83 x	2.08 x	2.06 x	1.32 x	1.89 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	2.77 x	2.19 x	2.63 x	2.41 x	1.39 x	2.28 x
Post-tax: All Interest Charges	2.15 x	1.82 x	2.08 x	2.04 x	1.29 x	1.88 x
Overall Coverage: All Int. & Pfd. Div.	2.15 x	1.82 x	2.08 x	2.04 x	1.29 x	1.88 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.9%	1.5%	0.4%	2.4%	8.7%	2.8%
Effective Income Tax Rate	34.6%	30.9%	33.7%	25.9%	23.8%	29.8%
Internal Cash Generation/Construction (4)	134.4%	96.3%	132.2%	98.7%	89.3%	110.2%
Gross Cash Flow/ Avg. Total Debt (5)	19.8%	19.1%	19.9%	12.4%	12.2%	16.7%
Gross Cash Flow Interest Coverage (6)	4.32 x	3.99 x	4.40 x	3.02 x	2.95 x	3.74 x
Common Dividend Coverage (7)	3.31 x	3.36 x	4.48 x	3.00 x	2.79 x	3.39 x

See Page 2 for Notes.

Indiana Gas Company, d/b/a Vectren North
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Utility COMPUSTAT

Gas Group
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,690.1	$ 1,434.8	$ 1,155.1	$ 1,066.3	$ 1,040.3	
Short-Term Debt	$ 173.1	$ 133.1	$ 218.6	$ 141.2	$ 141.8	
Total Capital	$ 1,863.2	$ 1,567.9	$ 1,373.7	$ 1,207.5	$ 1,182.1	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	16 x	16 x	14 x	17 x	15 x	16 x
Market/Book Ratio	195.9%	186.4%	179.4%	167.2%	176.4%	181.1%
Dividend Yield	3.8%	4.1%	4.6%	5.1%	4.9%	4.5%
Dividend Payout Ratio	61.2%	63.2%	63.0%	86.3%	70.4%	68.8%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	46.6%	46.6%	47.2%	50.9%	51.5%	48.5%
Preferred Stock	0.4%	0.4%	0.3%	0.4%	0.8%	0.5%
Common Equity [2]	53.0%	53.0%	52.6%	48.7%	47.7%	51.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	52.2%	51.7%	56.2%	56.7%	57.4%	54.8%
Preferred Stock	0.4%	0.4%	0.3%	0.4%	0.7%	0.4%
Common Equity [2]	47.4%	47.9%	43.5%	42.9%	41.9%	44.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	12.0%	12.0%	12.9%	10.6%	12.3%	12.0%
Operating Ratio [3]	89.8%	88.8%	87.4%	85.8%	88.6%	88.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.25 x	4.40 x	4.26 x	3.33 x	3.35 x	3.92 x
Post-tax: All Interest Charges	3.01 x	3.10 x	3.01 x	2.43 x	2.47 x	2.80 x
Overall Coverage: All Int. & Pfd. Div.	3.00 x	3.09 x	2.99 x	2.41 x	2.41 x	2.78 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.24 x	4.38 x	4.24 x	3.31 x	3.32 x	3.90 x
Post-tax: All Interest Charges	3.00 x	3.09 x	2.99 x	2.42 x	2.43 x	2.79 x
Overall Coverage: All Int. & Pfd. Div.	2.99 x	3.07 x	2.98 x	2.39 x	2.37 x	2.76 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.8%	1.0%	1.0%	1.1%	2.4%	1.3%
Effective Income Tax Rate	37.6%	37.6%	37.7%	38.3%	37.3%	37.7%
Internal Cash Generation/Construction [5]	82.1%	95.1%	117.8%	79.6%	79.0%	90.7%
Gross Cash Flow/ Avg. Total Debt [6]	19.6%	21.2%	21.7%	17.6%	17.9%	19.6%
Gross Cash Flow Interest Coverage [7]	4.37 x	5.07 x	5.13 x	3.95 x	3.63 x	4.43 x
Common Dividend Coverage [8]	2.97 x	3.43 x	3.62 x	3.04 x	2.81 x	3.17 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) they have not recently cut or omitted their dividend, (v) they are not currently the target of a merger or acquisition, (vi) they operate with a weather normalization and/or decoupling feature to their tariff or have other similar features, and (vii) they have at least 70% of their assets subject to utility regulation.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
ATG	AGL Resources, Inc.	A3	A-	NYSE	A-	0.95
ATO	Atmos Energy Corp.	Baa3	BBB	NYSE	B+	0.80
LG	Laclede Group, Inc.	Baa1	A	NYSE	B+	0.85
NJR	New Jersey Resources Corp	Aa3	A+	NYSE	A	0.80
NWN	Northwest Natural Gas	A3	AA-	NYSE	B+	0.75
PNY	Piedmont Natural Gas Co.	A3	A	NYSE	A-	0.80
SJI	South Jersey Industries, Inc.	Baa2	BBB+	NYSE	B+	0.70
WGL	WGL Holdings, Inc.	A2	AA-	NYSE	B+	0.85
	Average	A3	A		B+	0.81

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,644.5	$ 14,562.2	$14,658.8	$ 14,236.2	$13,783.4	
Short-Term Debt	$ 485.3	$ 278.7	$ 276.6	$ 952.3	$ 1,204.1	
Total Capital	$ 15,129.8	$ 14,840.9	$14,935.4	$ 15,188.5	$14,987.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	15 x	13 x	15 x	17 x	16 x
Market/Book Ratio	195.5%	180.1%	149.0%	151.3%	183.6%	171.9%
Dividend Yield	3.7%	3.8%	4.2%	5.0%	4.1%	4.2%
Dividend Payout Ratio	58.9%	73.3%	59.9%	75.3%	64.1%	66.3%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.6%	58.3%	59.8%	60.4%	58.9%	58.8%
Preferred Stock	1.2%	1.5%	1.6%	1.8%	2.3%	1.7%
Common Equity [2]	42.2%	40.2%	38.6%	37.8%	38.9%	39.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.5%	59.7%	61.3%	63.5%	62.9%	61.2%
Preferred Stock	1.2%	1.5%	1.6%	1.6%	2.1%	1.6%
Common Equity [2]	40.3%	38.8%	37.2%	34.9%	35.0%	37.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.9%	11.1%	9.8%	7.7%	14.5%	10.8%
Operating Ratio [3]	83.0%	84.5%	84.9%	84.5%	85.9%	84.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.01 x	2.88 x	2.51 x	2.36 x	2.84 x	2.72 x
Post-tax: All Interest Charges	2.41 x	2.32 x	2.07 x	1.95 x	2.22 x	2.19 x
Overall Coverage: All Int. & Pfd. Div.	2.37 x	2.28 x	2.03 x	1.90 x	2.17 x	2.15 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.97 x	2.85 x	2.47 x	2.31 x	2.80 x	2.68 x
Post-tax: All Interest Charges	2.37 x	2.29 x	2.03 x	1.90 x	2.18 x	2.15 x
Overall Coverage: All Int. & Pfd. Div.	2.34 x	2.25 x	1.99 x	1.86 x	2.13 x	2.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.9%	3.1%	1.7%	2.6%	2.0%	2.1%
Effective Income Tax Rate	31.6%	26.3%	40.9%	29.4%	28.1%	31.3%
Internal Cash Generation/Construction [5]	110.4%	127.2%	128.0%	90.6%	88.6%	109.0%
Gross Cash Flow/ Avg. Total Debt [6]	19.7%	19.7%	20.3%	18.2%	17.7%	19.1%
Gross Cash Flow Interest Coverage [7]	4.20 x	4.21 x	4.34 x	3.98 x	3.57 x	4.06 x
Common Dividend Coverage [8]	4.12 x	4.83 x	5.20 x	4.07 x	3.83 x	4.41 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities [1]

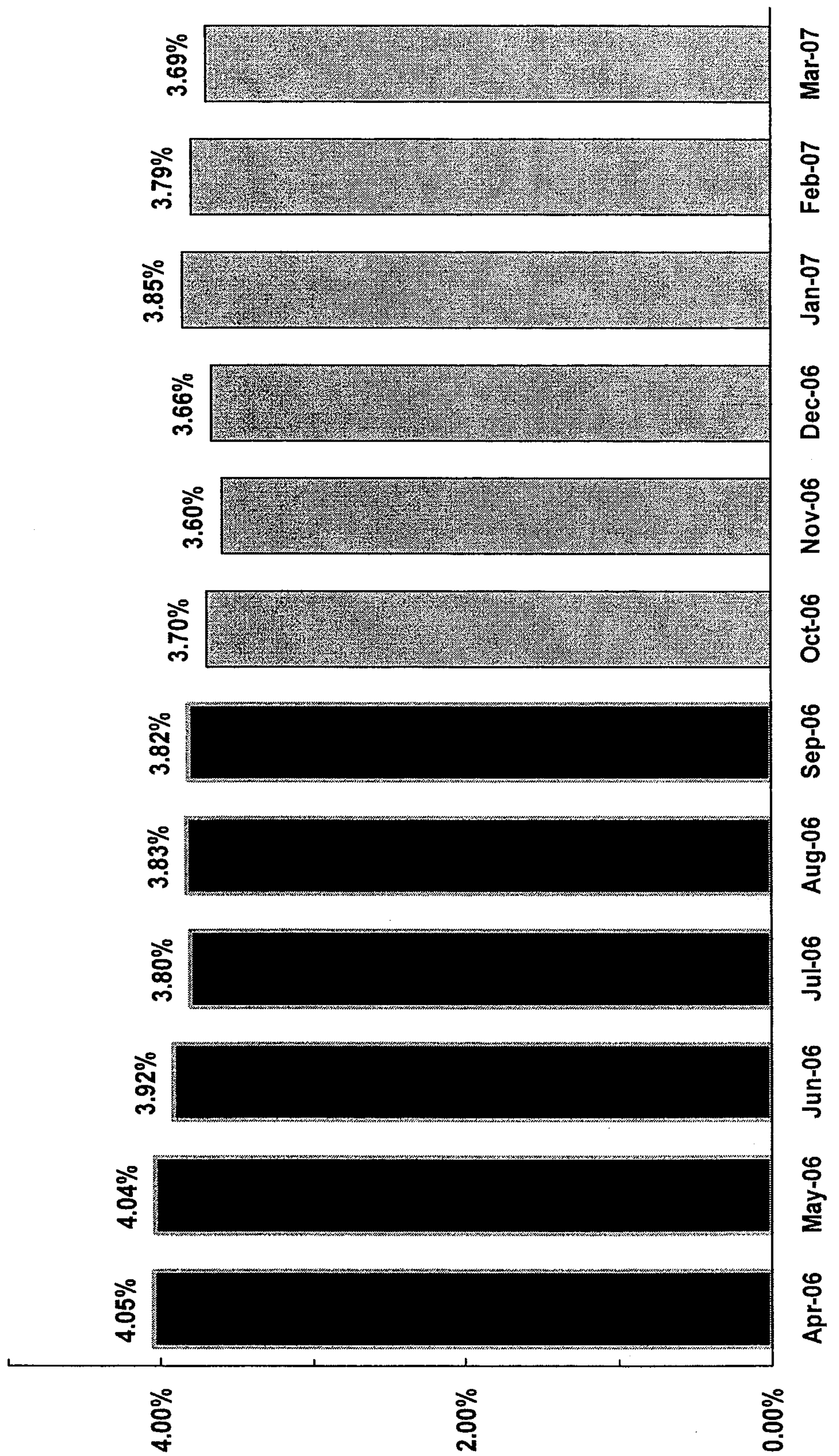
	Ticker	Credit Rating [2] Moody's	Credit Rating [2] S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Baa3	BB+	NYSE	B-	1.85
Ameren Corporation	AEE	A2	BBB+	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB	NYSE	B	1.20
CMS Energy	CMS	Ba1	BB	NYSE	C	1.45
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.65
Consolidated Edison	ED	A1	A	NYSE	B+	0.65
Constellation Energy Group	CEG	A3	BBB+	NYSE	B	0.95
DTE Energy Co.	DTE	Baa1	BBB	NYSE	B+	0.70
Dominion Resources	D	Baa1	BBB	NYSE	B+	0.95
Duke Energy	DUK	Baa2	BBB	NYSE	B+	1.20
Edison Int'l	EIX	Baa1	BBB+	NYSE	B	1.05
Entergy Corp.	ETR	Baa2	BBB	NYSE	B+	0.85
Exelon Corp.	EXC	A3	BBB+	NYSE	B+	0.80
FPL Group	FPL	A1	A	NYSE	A-	0.80
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B	0.85
NICOR Inc.	GAS	A1	AA	NYSE	B	1.15
NiSource Inc.	NI	Baa2	BBB	NYSE	B	0.80
PG&E Corp.	PCG	Baa1	BBB	NYSE	B	1.10
PPL Corp.	PPL	Baa1	A-	NYSE	B	1.00
Peoples Energy	PGL	A1	A-	NYSE	B	0.85
Pinnacle West Capital	PNW	Baa2	BBB-	NYSE	A-	0.90
Progress Energy, Inc.	PGN	Baa1	BBB	NYSE	B+	0.80
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.90
Sempra Energy	SRE	A2	A	NYSE	B	1.00
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	Baa2	BBB-	NYSE	B-	1.00
TXU CORP	TXU	Baa3	BBB-	NYSE	B	1.05
Xcel Energy Inc	XEL	A3	BBB+	NYSE	B	0.80
Average for S&P Utilities		Baa1	BBB+		B	0.95

Note: [1] Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.
[2] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

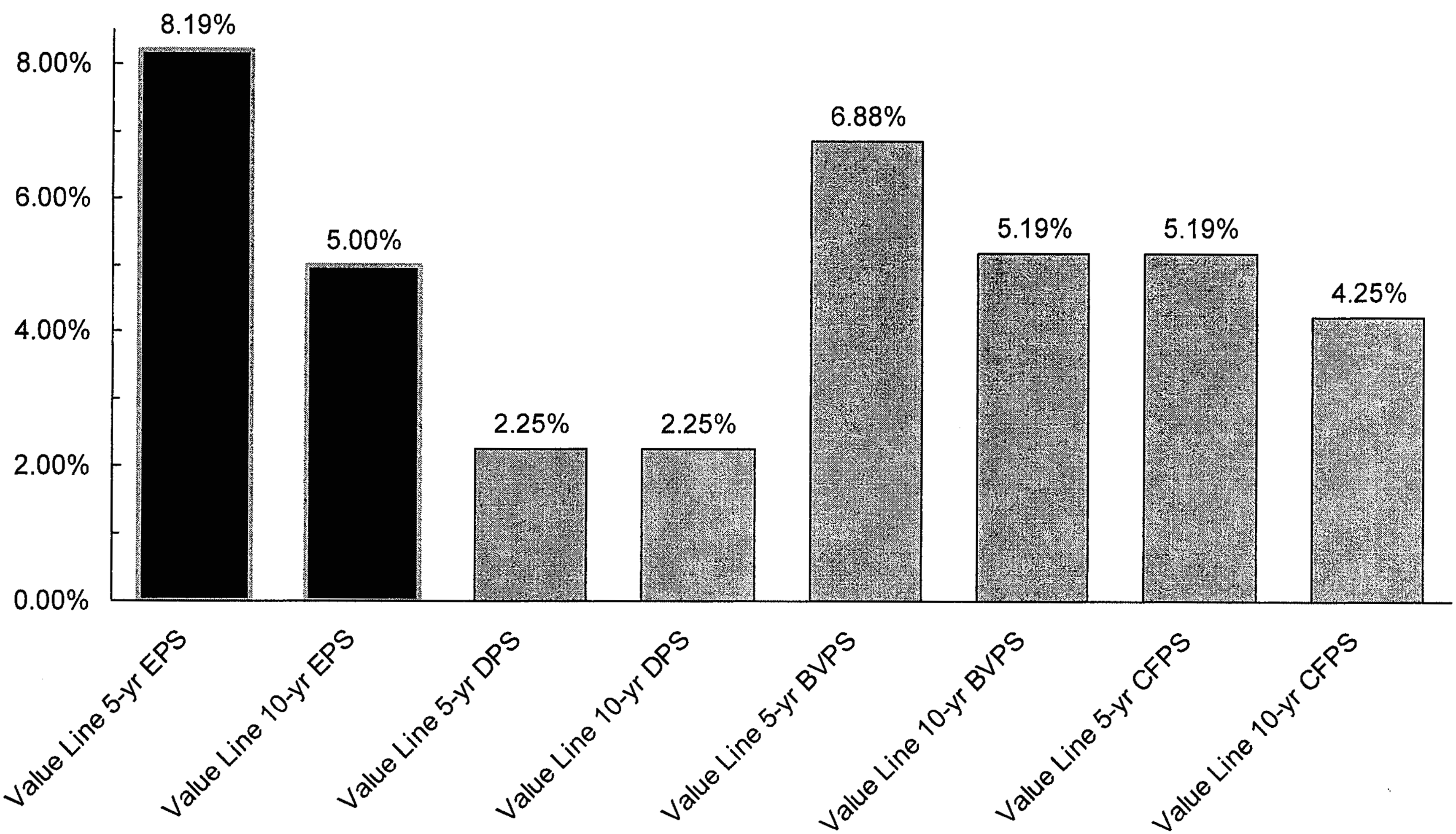
Gas Group

Monthly Dividend Yields



Gas Group

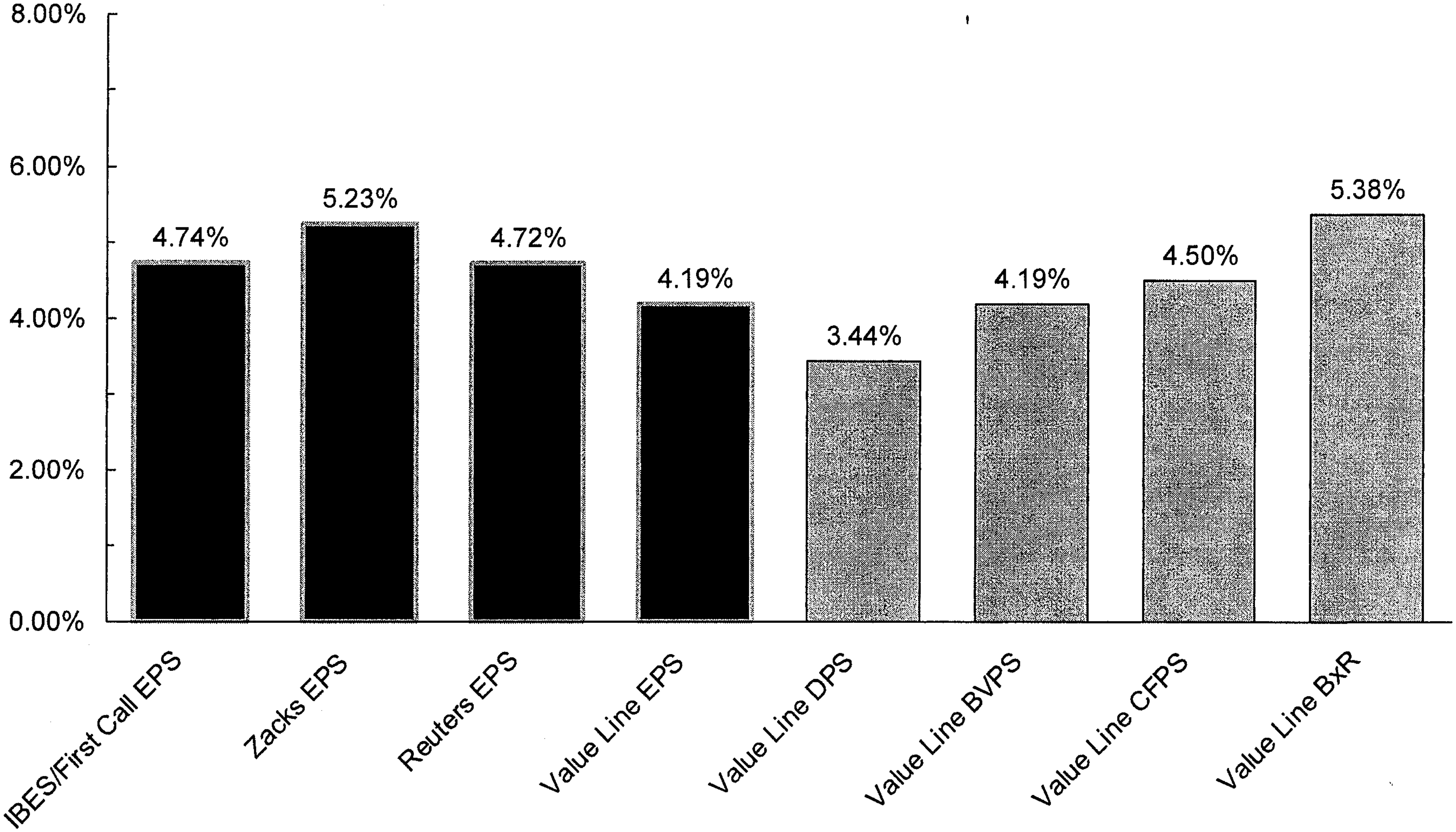
Historical Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Gas Group

Five-Year Projected Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

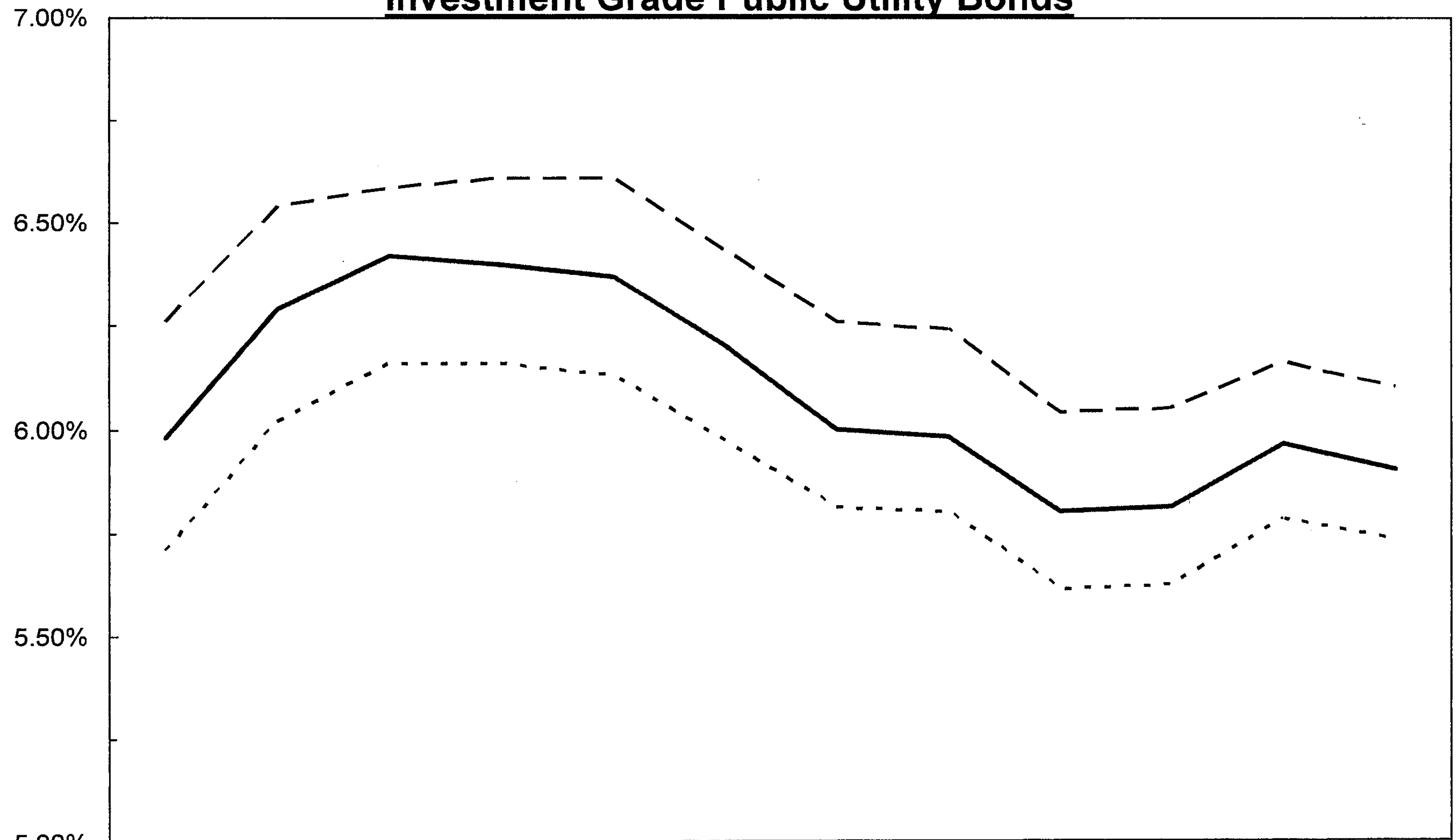
Natural Gas Industry
Analysis of Public Offerings of Common Stock
Years 2002-2006

	UTILICORP	MDU Resources	AGL RESOURCES	SOUTHERN UNION CO.	ATMOS ENERGY	VECTREN CORP.	SEMPRA ENERGY	PIEDMONT NATURAL	UGI CORP.
Date of Offering	1/25/2002	11/29/2002	2/11/2003	6/5/2003	6/18/2003	8/7/2003	10/8/2003	1/20/2004	3/18/2004
No. of shares offered (000)	11,000	2,100	5,600	9,500	4,000	6,500	15,000	4,250	7,500
Dollar amt. of offering ($000)	$ 253,000	$ 50,400	$ 123,200	$ 152,000	$ 101,240	$ 148,265	$ 420,000	$ 180,625	$ 240,750
Price to public	$ 23.000	$ 24.200	$ 22.000	$ 16.000	$ 25.310	$ 22.810	$ 28.000	$ 42.500	$ 32.100
Underwriter's discounts and commission	$ 0.748	$ 0.720	$ 0.770	$ 0.560	$ 1.013	$ 0.798	$ 0.840	$ 1.490	$ 1.404
Gross Proceeds	$ 22.252	$ 23.480	$ 21.230	$ 15.440	$ 24.297	$ 22.012	$ 27.160	$ 41.010	$ 30.696
Estimated company issuance expenses	NA	$ 0.092	$ 0.045	$ 0.089	$ 0.095	$ 0.046	$ 0.033	NA	$ 0.020
Net proceeds to company per share	$ 22.252	$ 23.388	$ 21.185	$ 15.351	$ 24.202	$ 21.966	$ 27.127	$ 41.010	$ 30.676
Underwriter's discount as a percent of offering price	3.3%	3.0%	3.5%	3.5%	4.0%	3.5%	3.0%	3.5%	4.4%
Issuance expense as a percent of offering price	NA	0.4%	0.2%	0.6%	0.4%	0.2%	0.1%	NA	0.1%
Total Issuance and selling expense as as a percent of offering price	3.3%	3.4%	3.7%	4.1%	4.4%	3.7%	3.1%	3.5%	4.5%

	NORTHWEST NATURAL	LACLEDE GROUP	SOUTHERN UNION CO.	AQUILA	ATMOS ENERGY	AGL RESOURCES	SOUTHERN UNION CO.	SEMCO Energy	Chesapeake Utilities	Average
Date of Offering	3/30/2004	5/6/2004	7/26/2004	8/18/2004	10/21/2004	11/19/2004	2/7/2005	8/9/2005	11/15/2006	
No. of shares offered (000)	1,200	1,500	11,000	40,000	14,000	9,600	14,913	4,300	600.3	
Dollar amt. of offering ($000)	$ 37,200	$ 40,200	$ 206,250	$ 102,000	$ 346,500	$ 297,696	$ 342,999	$ 27,176	$ 18,069	
Price to public	$ 31.000	$ 26.800	$ 18.750	$ 2.550	$ 24.750	$ 31.010	$ 23.000	$ 6.320	$ 30.100	
Underwriter's discounts and commission	$ 1.010	$ 0.871	$ 0.656	$ 0.099	$ 0.990	$ 0.930	$ 0.700	$ 0.253	$ 1.125	
Gross Proceeds	$ 29.990	$ 25.929	$ 18.094	$ 2.451	$ 23.760	$ 30.080	$ 22.300	$ 6.067	$ 28.975	
Estimated company issuance expenses	$ 0.146	$ 0.067	$ 0.091	NA	NA	$ 0.042	$ 0.067	$ 0.070	$ 0.375	
Net proceeds to company per share	$ 29.844	$ 25.862	$ 18.003	$ 2.451	$ 23.760	$ 30.038	$ 22.233	$ 5.997	$ 28.600	
Underwriter's discount as a percent of offering price	3.3%	3.3%	3.5%	3.9%	4.0%	3.0%	3.0%	4.0%	3.7%	3.5%
Issuance expense as a percent of offering price	0.5%	0.3%	0.5%	NA	NA	0.1%	0.3%	1.1%	1.2%	0.4%
Total Issuance and selling expense as as a percent of offering price	3.8%	3.6%	4.0%	3.9%	4.0%	3.1%	3.3%	5.1%	4.9%	3.9%

Source of Information: Public Utility Financial Tracker

Interest Rates for
Investment Grade Public Utility Bonds



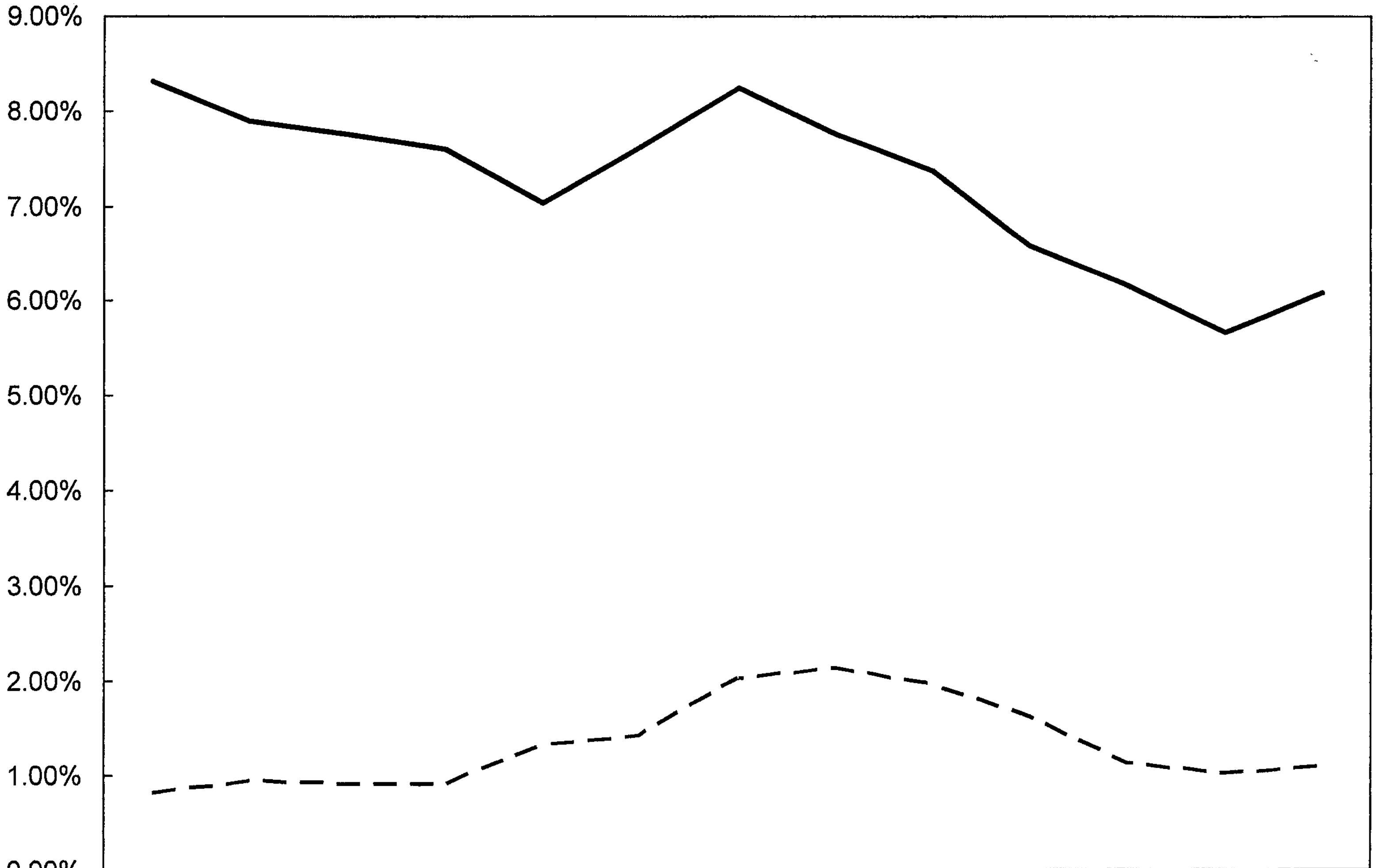
	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07
Aa	5.71%	6.02%	6.16%	6.16%	6.13%	5.97%	5.81%	5.80%	5.61%	5.62%	5.78%	5.73%
A	5.98%	6.29%	6.42%	6.40%	6.37%	6.20%	6.00%	5.98%	5.80%	5.81%	5.96%	5.90%
Baa	6.26%	6.54%	6.59%	6.61%	6.61%	6.43%	6.26%	6.24%	6.04%	6.05%	6.16%	6.10%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2001-2005 and 2006
and the Twelve Months Ended February 2007

Years	Aa Rated	A Rated	Baa Rated	Average
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
2005	5.44%	5.65%	5.93%	5.67%
Five-Year Average	6.53%	6.70%	7.04%	6.75%
2006	5.84%	6.07%	6.32%	6.08%
Months				
Mar-06	5.71%	5.98%	6.26%	5.98%
Apr-06	6.02%	6.29%	6.54%	6.28%
May-06	6.16%	6.42%	6.59%	6.39%
Jun-06	6.16%	6.40%	6.61%	6.39%
Jul-06	6.13%	6.37%	6.61%	6.37%
Aug-06	5.97%	6.20%	6.43%	6.20%
Sep-06	5.81%	6.00%	6.26%	6.03%
Oct-06	5.80%	5.98%	6.24%	6.01%
Nov-06	5.61%	5.80%	6.04%	5.82%
Dec-06	5.62%	5.81%	6.05%	5.83%
Jan-07	5.78%	5.96%	6.16%	5.96%
Feb-07	5.73%	5.90%	6.10%	5.91%
Twelve-Month Average	5.88%	6.09%	6.32%	6.10%
Six-Month Average	5.73%	5.91%	6.14%	5.93%
Three-Month Average	5.71%	5.89%	6.10%	5.90%

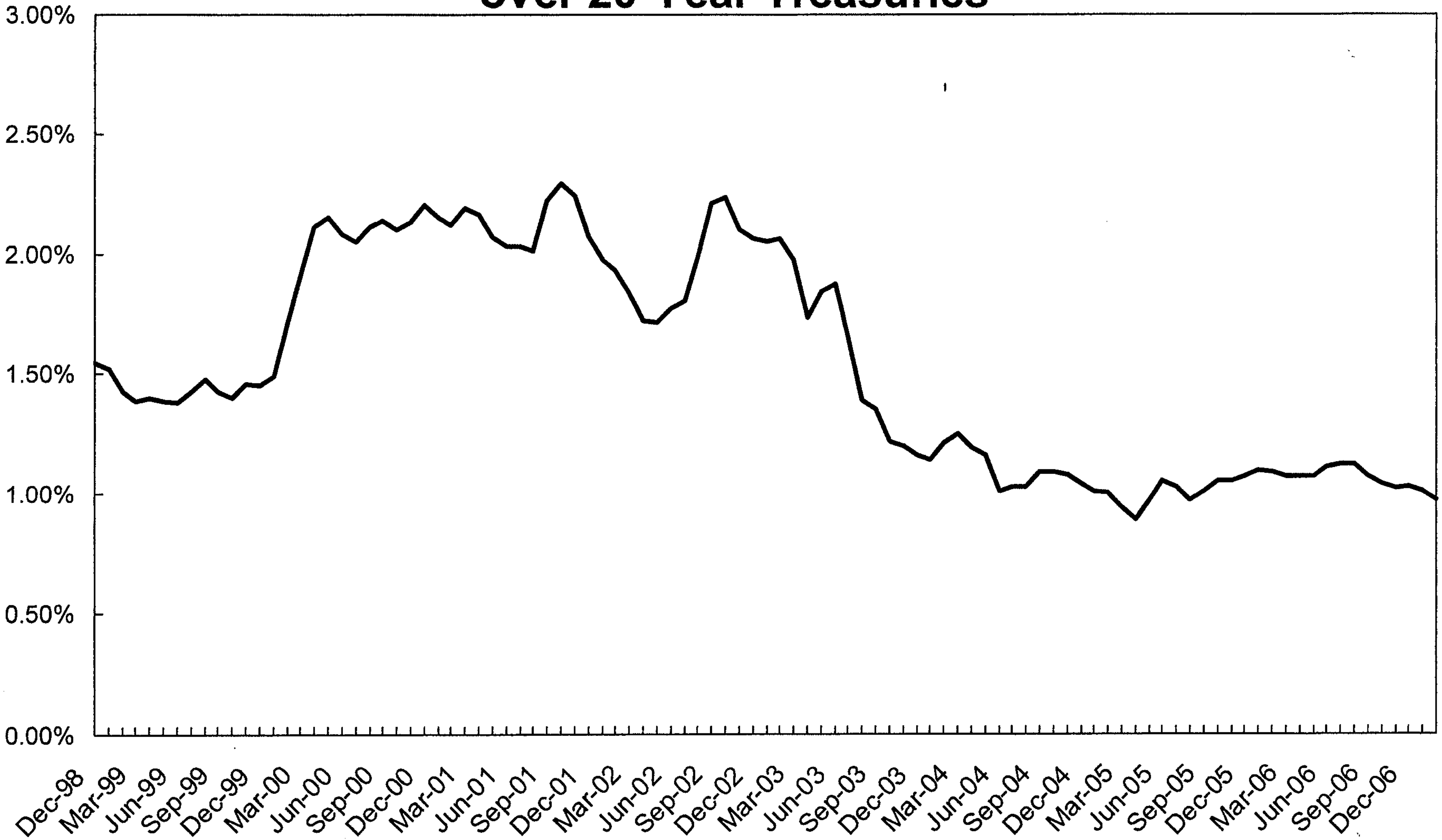
Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%	1.08%

Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries



A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%
Feb-06	5.82%	4.73%	1.09%
Mar-06	5.98%	4.91%	1.07%
Apr-06	6.29%	5.22%	1.07%
May-06	6.42%	5.35%	1.07%
Jun-06	6.40%	5.29%	1.11%
Jul-06	6.37%	5.25%	1.12%
Aug-06	6.20%	5.08%	1.12%
Sep-06	6.00%	4.93%	1.07%
Oct-06	5.98%	4.94%	1.04%
Nov-06	5.80%	4.78%	1.02%
Dec-06	5.81%	4.78%	1.03%
Jan-07	5.96%	4.95%	1.01%
Feb-07	5.90%	4.93%	0.97%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2006

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005	4.91%	16.79%	5.87%	3.02%
2006	15.80%	20.95%	3.24%	3.94%
Geometric Mean	10.10%	8.80%	5.85%	5.45%
Arithmetic Mean	12.03%	11.14%	6.17%	5.73%
Standard Deviation	20.13%	22.55%	8.57%	7.89%
Median	14.31%	11.74%	4.14%	4.45%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2006, 1952-2006, 1974-2006, and 1979-2006

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2006					
S&P Public Utility Index	8.80%	11.74%		11.14%	
Public Utility Bonds	5.45%	4.45%		5.73%	
Risk Differential	3.35%	7.29%	5.32%	5.41%	5.37%
1952-2006					
S&P Public Utility Index	10.99%	13.58%		12.53%	
Public Utility Bonds	6.17%	4.94%		6.47%	
Risk Differential	4.82%	8.64%	6.73%	6.06%	6.40%
1974-2006					
S&P Public Utility Index	12.79%	15.08%		14.77%	
Public Utility Bonds	8.55%	8.65%		8.90%	
Risk Differential	4.24%	6.43%	5.34%	5.87%	5.61%
1979-2006					
S&P Public Utility Index	13.42%	15.94%		15.27%	
Public Utility Bonds	8.96%	9.05%		9.29%	
Risk Differential	4.46%	6.89%	5.68%	5.98%	5.83%

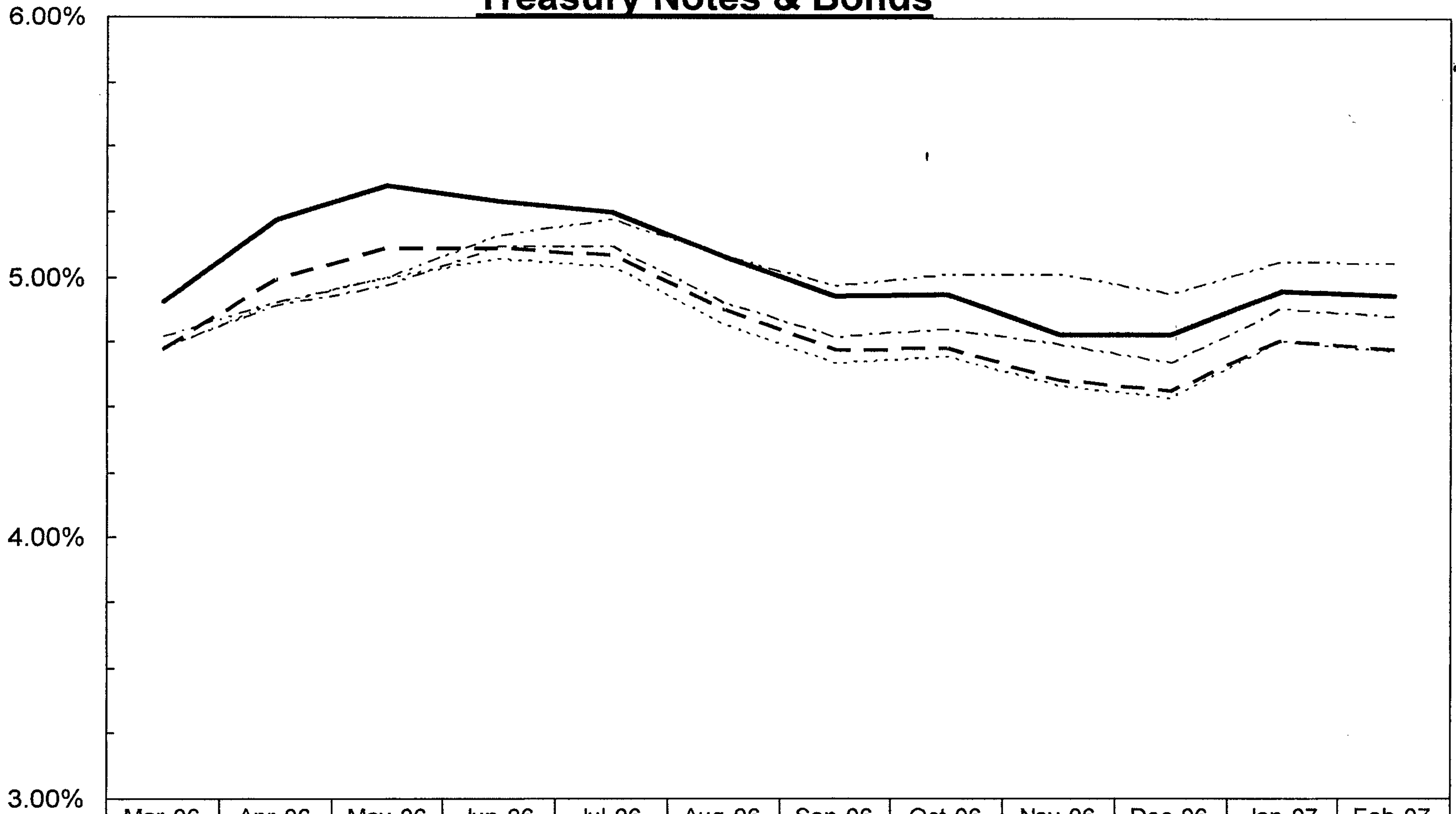
Value Line Betas

Gas Group

AGL Resources, Inc.	0.95
Atmos Energy Corp.	0.80
Laclede Group, Inc.	0.85
New Jersey Resources Corp.	0.80
Northwest Natural Gas	0.75
Piedmont Natural Gas Co.	0.80
South Jersey Industries, Inc.	0.70
WGL Holdings, Inc.	0.85
Average	0.81

Source of Information:
Value Line Investment Survey
March 17, 2006

Yields on
Treasury Notes & Bonds



	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07
1-Year	4.77%	4.90%	5.00%	5.16%	5.22%	5.08%	4.97%	5.01%	5.01%	4.94%	5.06%	5.05%
2-Year	4.73%	4.89%	4.97%	5.12%	5.12%	4.90%	4.77%	4.80%	4.74%	4.67%	4.88%	4.85%
5-Year	4.72%	4.90%	5.00%	5.07%	5.04%	4.82%	4.67%	4.69%	4.58%	4.53%	4.75%	4.71%
10-Year	4.72%	4.99%	5.11%	5.11%	5.09%	4.88%	4.72%	4.73%	4.60%	4.56%	4.76%	4.72%
20-Year	4.91%	5.22%	5.35%	5.29%	5.25%	5.08%	4.93%	4.94%	4.78%	4.78%	4.95%	4.93%

Yields for Treasury Constant Maturities
Yearly for 2001-2005 and 2006
and the Twelve Months Ended February 2007

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.10%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.04%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.64%
Five-Year Average	2.45%	2.87%	3.20%	3.77%	4.14%	4.44%	5.14%
2006	4.93%	4.82%	4.77%	4.75%	4.76%	4.79%	4.99%
Months							
Mar-06	4.77%	4.73%	4.74%	4.72%	4.71%	4.72%	4.91%
Apr-06	4.90%	4.89%	4.89%	4.90%	4.94%	4.99%	5.22%
May-06	5.00%	4.97%	4.97%	5.00%	5.03%	5.11%	5.35%
Jun-06	5.16%	5.12%	5.09%	5.07%	5.08%	5.11%	5.29%
Jul-06	5.22%	5.12%	5.07%	5.04%	5.05%	5.09%	5.25%
Aug-06	5.08%	4.90%	4.85%	4.82%	4.83%	4.88%	5.08%
Sep-06	4.97%	4.77%	4.69%	4.67%	4.68%	4.72%	4.93%
Oct-06	5.01%	4.80%	4.72%	4.69%	4.69%	4.73%	4.94%
Nov-06	5.01%	4.74%	4.64%	4.58%	4.58%	4.60%	4.78%
Dec-06	4.94%	4.67%	4.58%	4.53%	4.54%	4.56%	4.78%
Jan-07	5.06%	4.88%	4.79%	4.75%	4.75%	4.76%	4.95%
Feb-07	5.05%	4.85%	4.75%	4.71%	4.71%	4.72%	4.93%
Twelve-Month Average	5.01%	4.87%	4.82%	4.79%	4.80%	4.83%	5.03%
Six-Month Average	5.01%	4.79%	4.70%	4.66%	4.66%	4.68%	4.89%
Three-Month Average	5.02%	4.80%	4.71%	4.66%	4.67%	4.68%	4.89%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated April 1, 2007

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	30-Year Treasury Bond
2007	Second	5.0%	4.7%	4.6%	4.7%	4.8%
2007	Third	4.9%	4.7%	4.7%	4.7%	4.9%
2007	Fourth	4.9%	4.8%	4.7%	4.8%	4.9%
2008	First	4.9%	4.8%	4.8%	4.8%	5.0%
2008	Second	4.9%	4.8%	4.8%	4.8%	5.0%
2008	Third	4.9%	4.8%	4.8%	4.9%	5.0%

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

THE VALUE LINE® Investment Survey®

Part 1 **Summary & Index**

March 30, 2007

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

18.6

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
17.6	14.1	19.6

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.7%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
1.7%	2.4%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

40%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
45%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXII, No. 31.
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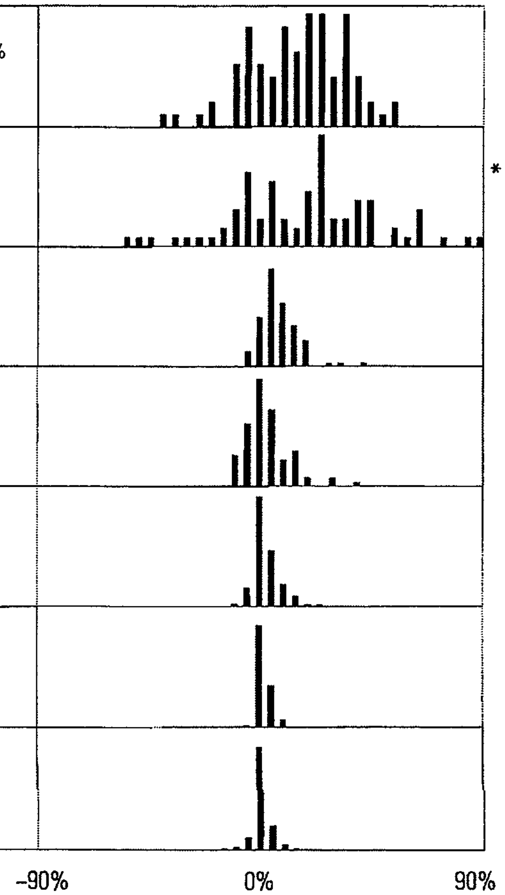
See back cover for important disclosures.

Table 2-1
Basic Series: Summary Statistics of Annual Total Returns

Petitioner's Exhibit No. PRM-2
Vectren North
Page 27 of 30
Schedule 11 [6 of 6

from 1926 to 2006

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.3%	20.1%	
Small Company Stocks	12.7	17.4	32.7	*
Long-Term Corporate Bonds	5.9	6.2	8.5	
Long-Term Government	5.4	5.8	9.2	
Intermediare-Term Government	5.3	5.4	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.3	



*The 1933 Small Company Stocks Total Return was 142.9 percent.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 3, 4 & 5; Safety Rank of 1 & 2; Financial Strength of B+, B++ & A;
Price Stability of 95 to 100; Betas of .70 to .95; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Air Products & Chem.	CHEMDIV	3	2	B++	95	0.95	3
Allstate Corp.	INSPRPTY	3	1	A	95	0.90	3
Assoc. Banc-Corp	BANKMID	4	2	B++	100	0.90	3
Bank of Hawaii	BANK	3	2	B++	100	0.85	3
BB&T Corp.	BANK	3	1	A	100	0.95	4
BOK Financial	BANKMID	4	2	B++	95	0.90	3
Campbell Soup	FOODPROC	3	2	B++	100	0.75	3
Capitol Fed. Fin'l	THRIFT	3	2	B++	95	0.70	3
Cincinnati Financial	INSPRPTY	4	2	B++	100	0.90	3
Commerce Bancshs.	BANKMID	4	1	A	100	0.90	3
Ecolab Inc.	CHEMSPEC	3	1	A	100	0.80	3
First Midwest Bancorp	BANKMID	4	2	B++	95	0.95	3
Genworth Fin'l -	INSLIFE	3	2	B++	95	0.95	3
Hormel Foods	FOODPROC	4	1	A	95	0.75	3
Huntington Bancshs.	BANKMID	4	2	B++	100	0.90	3
McClatchy Co.	NWSPAPER	5	1	A	95	0.75	3
Mercury General	INSPRPTY	4	2	B++	95	0.85	3
National City Corp.	BANKMID	3	1	A	95	0.95	3
Northrop Grumman	DEFENSE	3	2	B++	95	0.80	3
Old Nat'l Bancorp	BANKMID	3	2	B++	100	0.75	3
Pitney Bowes	OFFICE	3	1	A	100	0.90	3
Popular Inc.	BANK	5	2	B+	100	0.80	3
Praxair Inc.	CHEMSPEC	3	2	B++	95	0.95	3
Protective Life	INSLIFE	5	2	B++	95	0.95	3
Reinsurance Group	INSLIFE	3	2	B++	95	0.90	3
Scripps (E.W.) 'A'	NWSPAPER	3	2	B+	95	0.80	3
Sigma-Aldrich	CHEMSPEC	3	1	A	95	0.85	3
Union Pacific	RAILROAD	3	1	A	95	0.90	3
Wilmington Trust	BANK	4	1	A	95	0.95	3
Average		4	2	B++	97	0.87	3
Gas Group	Average	4	2	B++	99	0.81	3

Source of Information: Value Line Investment Survey for Windows, March 2007

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2001-2005 and
Projected 3-5 Year Returns

Company	2001	2002	2003	2004	2005	Average	Projected 2009-11
Air Products & Chem.	16.7%	15.0%	13.1%	13.6%	15.6%	14.8%	23.0%
Allstate Corp.	6.9%	11.9%	12.9%	14.2%	8.7%	10.9%	11.5%
Assoc. Banc-Corp	16.8%	16.6%	17.0%	12.8%	13.8%	15.4%	13.5%
Bank of Hawaii	9.4%	11.9%	17.0%	21.3%	26.2%	17.2%	20.5%
BB&T Corp.	17.9%	17.9%	10.7%	14.3%	14.9%	15.1%	16.0%
BOK Financial	15.2%	13.8%	12.9%	12.8%	13.1%	13.6%	12.0%
Campbell Soup	-	-	161.8%	74.7%	55.7%	97.4%	34.0%
Capitol Fed. Fin'l	7.4%	9.1%	5.3%	4.8%	7.5%	6.8%	7.5%
Cincinnati Financial	3.2%	5.4%	6.2%	8.4%	9.2%	6.5%	8.0%
Commerce Bancshs.	14.3%	14.1%	14.2%	15.4%	16.7%	14.9%	13.0%
Ecolab Inc.	21.4%	21.9%	21.2%	20.0%	19.4%	20.8%	24.5%
First Midwest Bancorp	18.4%	18.3%	17.8%	18.6%	18.6%	18.3%	20.5%
Genworth Fin'l	-	-	6.1%	8.7%	9.2%	8.0%	9.5%
Hormel Foods	18.3%	17.0%	14.8%	15.6%	16.1%	16.4%	15.5%
Huntington Bancshs.	12.1%	14.8%	17.0%	15.7%	16.1%	15.1%	14.0%
McClatchy Co.	6.3%	12.5%	11.9%	11.1%	10.3%	10.4%	7.0%
Mercury General	9.8%	10.2%	14.1%	18.4%	15.1%	13.5%	15.0%
National City Corp.	18.8%	19.2%	22.7%	17.1%	15.7%	18.7%	14.0%
Northrop Grumman	5.5%	4.8%	4.8%	6.4%	7.4%	5.8%	11.5%
Old Nat'l Bancorp	15.5%	14.8%	9.8%	9.6%	12.1%	12.4%	14.0%
Pitney Bowes	62.4%	67.0%	52.3%	46.0%	48.1%	55.2%	42.5%
Popular Inc.	13.4%	14.6%	17.1%	15.8%	15.6%	15.3%	11.5%
Praxair Inc.	19.6%	23.4%	18.8%	19.3%	21.1%	20.4%	22.0%
Protective Life	10.1%	10.0%	9.8%	10.9%	12.1%	10.6%	12.0%
Reinsurance Group	4.0%	10.5%	8.5%	9.9%	8.9%	8.4%	11.5%
Scripps (E.W.) 'A'	10.6%	15.2%	13.6%	13.8%	13.7%	13.4%	13.5%
Sigma-Aldrich	17.4%	14.8%	19.3%	19.2%	20.9%	18.3%	18.5%
Union Pacific	8.7%	9.3%	8.5%	6.0%	6.6%	7.8%	11.5%
Wilmington Trust	18.2%	18.0%	16.8%	15.7%	17.1%	17.2%	13.5%
Average						17.9%	15.9%
Median						14.9%	13.5%

Indiana Gas Company, d/b/a Vectren North

Rate of Return Applicable to a Fair Value Rate Base

Investor Provided Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.28%	6.86%	3.04%
Common Equity	55.72%	9.91%	5.52%
Total	100.00%		8.56%

For Ratesetting Purposes	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.93%	6.86%	2.68%
Common Equity	48.99%	9.91%	4.85%
Customer Deposits	2.08%	5.00%	0.10%
Cost-free Capital	9.82%	0.00%	0.00%
JDITC	0.18%	8.56%	0.02%
Total	100.00%		7.65%

INDIANA GAS COMPANY, INC.
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN NORTH)

IURC CAUSE NO. 43298

DIRECT TESTIMONY
OF
ROBERT L. GOOCHER
VICE PRESIDENT AND TREASURER

ON

COST OF CAPITAL

SPONSORING PETITIONER'S EXHIBITS RLG-1 THROUGH RLG-3

DIRECT TESTIMONY OF ROBERT L. GOOCHER

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert L. Goocher. My business address is One Vectren Square, Evansville, Indiana 47708.

Q. What is your position with Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North" or the "Company")?

A. I am Vice President and Treasurer of Vectren North. I also hold these same positions with Vectren Corporation ("Vectren"), Vectren Utility Holdings, Inc. ("VUHI"), Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. What is your educational background?

A. I graduated from the University of Georgia with a Bachelor of Business Administration with a major in accounting and from Georgia State University with a Master of Business Administration with a major in finance.

Q. Please describe your business experience.

A. I have over 30 years' experience in various financial, operational and administrative roles, primarily in the utility and energy industry. I worked at AGL Resources (parent company of Atlanta Gas Light Company) in Atlanta, GA and its predecessor companies in a variety of positions including Assistant Treasurer, Controller, Vice President and Augusta Division Manager, Chief Financial Officer, Executive Vice President-Business Support and President and Chief Operating Officer of AGL's shared services subsidiary. My most recent position prior to joining Vectren was Treasurer for GridSouth Transco in Charlotte, NC. On April 1, 2002, I joined Vectren as Vice President and Treasurer of Vectren, VUHI, and its three operating utilities, as well as a number of its non-regulated subsidiaries.

In addition, I have also been appointed to the board of directors of Vectren South and Vectren Capital Corporation.

Q. What are your responsibilities as Vice President and Treasurer of Vectren Corporation, VUHI, Vectren North, Vectren South and Vectren Ohio?

A. I am responsible for maintaining the security and liquidity of the Companies' working capital resources. This includes having responsibility for cash management, bank relations, short-term borrowings, long-term capital financing, leasing, capital allocation, capital resource planning, risk management, credit rating agency relations and a variety of other finance-related activities.

II. SUMMARY OF PRESENTATION

Q. What is the purpose and scope of your testimony in this proceeding?

A. My testimony and accompanying exhibits will provide an overview of the components of Vectren North's capital structure and its weighted average cost of capital.

III. COST OF CAPITAL

Q. How does Vectren North finance its operations?

A. Vectren North finances its operations through the issuance of securities (long-term debt and common stock). Although Vectren North still has some outstanding debt issues that existed at the time of the Vectren merger on March 31, 2000, all of Vectren North's additional permanent debt financing currently outstanding have been accomplished through the issuance of long-term debt by VUHI. It is Vectren's intention to continue to use VUHI as the principal entity to provide permanent debt financing for all of Vectren's utility subsidiaries, including Vectren North.

Q. What is your estimate of Vectren North's weighted average cost of capital?

A. In my opinion, Vectren North's cost of capital is 8.43%. <u>Petitioner's Exhibit RLG-2</u> shows how I derived this estimate.

Q. Please describe the investor-provided capital structure components that you have reflected in the computation of Vectren North's cost of capital.

A. Petitioner's Exhibit RLG-2, include Vectren North's actual investor-provided capitalization as of December 31, 2006. This results in an investor-provided capital structure consisting of 44.28% long-term debt and 55.72% common equity.

Q. How do these capital structure ratios compare with Vectren North's financial objectives?

A. These ratios seem to be generally supportive of its financial objectives. Vectren North currently has senior unsecured debt ratings of "Baa1" from Moody's Investors Service (stable outlook) and "A-" from Standard & Poor's Ratings Services (stable outlook). Vectren's goal for VUHI, Vectren North and Vectren South is to achieve and maintain a solid "A" credit rating for the senior unsecured debt. However, given that current credit ratings are below this benchmark, improvements will need to be made in various earnings and cash flow related financial metrics to achieve this goal. Continued improvements in these various financial metrics should provide Vectren North with the opportunity to maintain and improve current ratings levels over time.

Q. How do these investor-provided capitalization ratios of 44.28% long-term debt and 55.72% common equity compare with the comparable ratios for Vectren North at March 31, 2004, that was used in the final Commission Order in its previous rate case in Cause No. 42598 and to those for Vectren South at March 31, 2006 used in its electric and gas rate case proceedings in Cause Nos. 43111 and 43112, respectively?

A. They are very similar to both. At March 31, 2004, Vectren North's investor-provided capitalization consisted of 44.62% long-term debt and 55.38% common equity. Vectren South's investor-provided capitalization at March 31, 2006 consisted of 45.10% long-term debt and 54.90% common equity.

Q. What is the weighted cost of the long-term debt portion of Vectren North's capital structure?

A. As shown on Petitioner's Exhibit RLG-3, Vectren North's weighted cost of long-term debt is 6.86%. The details leading to the development of the effective cost rate for each series of long-term debt, using the cost rate to maturity technique, are shown on Petitioner's Exhibit RLG-3. The cost rate is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the long-term debt, *i.e.* the gross proceeds less issuance costs. This methodology is consistent with that used in the Vectren South - Electric and Vectren South – Gas rate proceedings, in Cause Nos. 43111 and 43112 respectively, in the Vectren South – Electric Multi-pollutant proceeding in Cause No. 42861 and in Vectren North's most recent rate proceeding in Cause No. 42598.

Q. Were there any changes to Vectren North's investor-provided capitalization during the test year?

A. Yes. In March 2006, VUHI loaned Vectren North $50 million of the proceeds of its November 2005 issuance of 6.10% Senior Notes due December 1, 2035 and $25 million of the proceeds of its 5.45% Senior Notes due December 1, 2015, which were issued by VUHI in November 2005. In October 2006, VUHI called at par and retired $100 million of its 7.25% Notes due October 2031, of which $50 million had been previously loaned to Vectren North. Also in October 2006, VUHI loaned Vectren North $35 million of the proceeds of its $100 million October 2006 issuance of 5.95% Notes due October 2036. This exhausted the remaining Vectren North long-term debt financing authority approved by the Commission in Cause No. 42888.

Q, Were there any benefits or costs included in the calculation of the effective interest rate of the new VUHI debt that was loaned to Vectren North in March and October 2006 related to interest rate hedging activities?

A. Yes. VUHI hedged a portion of its interest rate risk related to the new 6.10% 30-year debt issue due December 1, 2035, prior to issuance by utilizing Forward Starting Swaps. Interest rates rose following the execution of the interest rate hedges resulting in a gain of $1.3 million related to the $50 million Vectren North long-term debt proceeds provided by VUHI in March 2006. This gain will be amortized over the 30-year life of Vectren North's new debt issue as a reduction in interest expense, as provided in the financing Order received in Cause No. 42888. In addition, interest rates were hedged with Forward Starting Swaps prior to the issuance of the new 5.95% 30-year VUHI debt issue due October 1, 2036. Interest rates declined following the execution of the interest rate hedges resulting in a loss of $1.2 million related to the $35 million in proceeds loaned to Vectren North in October 2006. This loss will similarly be amortized over the 30-year life of the new Vectren North debt. VUHI often hedges its interest rate risk in advance of debt issuances in order to lock in refinancing savings expected and to price the new debt issue in pieces over time rather than on the single date of issuance. As a result, both gains and losses are possible from hedging activities as demonstrated by the March and October 2006 financings described above.

Q. What impact did recent debt financings have on Vectren North's weighted average cost of debt?

A. In Cause No. 42598, Vectren North's previous rate case proceeding, its weighted average cost of debt was determined to be 7.38% at March 31, 2004. Vectren North's weighted average cost of debt is 6.86% at December 31, 2006. During this period of time, in addition to the retirement of $2.5 million of long-term debt "put" to the Company in July 2004, Vectren North took advantage of the lower interest rate environment to call and refinance 3 debt issues totaling some $120 million, including the permanent debt financing during the test year previously discussed. The 52 basis point reduction in the weighted average cost of debt on over $371 million of outstanding long-term debt at December 31, 2006 equates to a reduction in annual interest expense of over $1.9 million. This represents a very significant reduction in annualized interest costs achieved over a short period of time. However, we do not see any comparable refinancing opportunities to further reduce the weighted average cost of debt over the next few years.

Q. What common equity cost rate did you use?

A. A cost rate of common equity of 11.50% was used in the determination of the overall cost of capital. Petitioner's Witness Paul R. Moul is testifying regarding Vectren North's cost of common equity capital (see Petitioner's Exhibit PRM-1).

Q. Does Petitioner's Exhibit RLG-2, include other capital structure components for purposes of determining Vectren North's cost of capital?

A. Yes. That exhibit includes customer deposits, as required by the Commission's rules, at the 5.0% interest rate for gas deposits that was set to be effective January 1, 2007 in the Commission's General Administrative Order dated December 20, 2006. Also included are Job Development Investment Tax Credits ("JDITC") at the overall weighted cost of investor-provided capital.

Q. Were there any cost-free components included in determining Vectren North's cost of capital?

A. Yes. Accumulated deferred income taxes, customer advances for construction, pre-1971 investment tax credits and Statement of Financial Accounting Standards No. 106 ("SFAS 106") costs in excess of the cash basis (or pay-as-you-go) amounts were included at zero cost.

Q. Please explain how the accumulated deferred tax balance shown on Petitioner's Exhibit RLG-2 was calculated.

A. Statement of Financial Accounting Standards No. 109 ("SFAS 109"), "Accounting for Income Taxes," of the Financial Accounting Standards Board requires deferred income taxes to be provided on the difference between the tax basis of assets and liabilities and the amounts at which they are carried in the financial statements. SFAS 109 requires regulated enterprises to provide deferred taxes on all temporary differences including those not previously recognized when the tax effect of the differences are, at the direction of regulatory authorities, essentially flowed through to the customers' benefit for ratemaking purposes. SFAS No. 109, Paragraph 29 further states that any regulatory assets or liabilities also create temporary timing differences. Therefore, regulated enterprises are also required to recognize changes in regulatory assets and liabilities for the effect on revenues expected to be realized as the tax effects of temporary differences reverse.

To adjust the deferred income tax liability to the gross amount, the above mentioned regulatory assets and liabilities were recorded in the deferred taxes account through a reclassification entry, which affects only the balance sheet. For consistency with prior rate cases and for simplicity of presentation, these regulatory assets and liabilities have been netted against the long-term deferred income tax liability. The result is a deferred income tax balance of $74.333 million included in capitalization, which is on the same basis as that recognized in previous rate cases.

Q. Please explain how the SFAS 106 amount included as cost-free capital was determined.

A. The cumulative SFAS 106 costs incurred by Vectren North in excess of cash payments made since the Commission authorized an increase in Vectren North's rates effective May 3, 1995, have been included at zero cost. This approach is consistent with the Commission's generic Order regarding SFAS 106 costs dated December 30, 1992 in Cause No. 39348 and with the approach utilized by Vectren North in its most recent rate case in Cause No. 42598, approved by the Commission on November 30, 2004 and in the Vectren South electric and gas cases in Cause Nos. 43111 and 43112, respectively. The $16.928 million component of cost-free capital was derived first by subtracting the SFAS 106 liability of $11.399 million that existed at October 1, 1995 for Vectren North's Postretirement Medical Plan from the estimated SFAS 106 liability of $35.339 million that exists at December 31, 2006 for that Plan. The $23.940 million increase in the liability over this period results from the net of the additional annual SFAS 106 accruals less the amount of benefits actually paid for each year. The final step in arriving at the proper amount to include as cost-free capital is to reduce the $23.940 million difference by 29.29%, which is the percentage of various costs that are capitalized and thus not included for recovery in operation and maintenance expenses. The $16.928 million remainder was then included in Vectren North's capital structure as cost-free capital.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

VECTREN NORTH COST OF CAPITAL
Capital Structure at December 31, 2006
($000's)

		Actual at 12/31/2006	Ratios	Cost		WCOC
1	**Long-Term Debt**					
2	Publicly Held	127,500	13.37%			
3	Notes to VUHI	243,838	25.56%			
4	Total Long-Term Debt	371,338	38.93%	6.86%		2.68%
5						
6	**Common Equity**					
7	Common Stock	367,995	38.58%			
8	Retained Earnings	99,286	10.41%			
9	Common Shareholder's Equity	467,281	48.99%	11.50%		5.63%
10						
11						
12	**Total Investor Provided Capital**	838,619	87.92%			8.31%
13						
14	**Customer Deposits**	19,842	2.08%	5.00%	(1)	0.10%
15						
16	**Cost-Free Capital**					
17	Deferred Income Taxes	74,333	7.79%			
18	Customer Advancements for Construction	2,304	0.24%			
19	Pre-1971 Investment Tax Credit	87	0.01%			
20	SFAS 106	16,928	1.78%			
21	Total Cost Free Capital	93,652	9.82%	0.00%		0.00%
22						
23	**Job Development Investment Tax Credit (Post-1971)**	1,731	0.18%	9.45%		0.02%
24						
25	**Total Capitalization**	$953,844	100.00%			8.43%
26						
27	**Investor Provided Capital**					
28						
29		**Amount**				
30		**($000's)**	**Ratios**	**Cost**		**WCOC**
31	Long Term Debt	$371,338	44.28%	6.86%		3.04%
32						
33	Common Equity	467,281	55.72%	11.50%		6.41%
34	Total Capitalization	$838,619	100.00%			9.45%

(1) Effective 1/1/07 per the Indiana Utility Regulatory Commission's General Administrative Order dated 12/20/06

Vectren North
Rate Case
Schedule of Long-Term Debt
December 31, 2006

1	**Long-Term Notes**	**Date of Issue**	**Maturity Date**	**Principal Amount Outstanding**	**Type**	**Total Discount and Expense Net of Premium**	**Net Proceeds**	**Effective Cost Rate**
2	6.54% Series E	07/08/97	07/09/07	6,500,000	SU	0	6,500,000	6.54%
3	6.69% Series E	12/19/95	06/10/13	5,000,000	SU	349,042	4,650,958	7.48%
4	7.15% Series E	06/09/95	03/15/15	5,000,000	SU	300,310	4,699,690	7.85%
5	6.69% Series E	12/19/95	12/21/15	5,000,000	SU	352,792	4,647,208	7.49%
6	6.69% Series E	12/26/95	12/29/15	10,000,000	SU	708,585	9,291,415	7.49%
7	6.53% Series E	06/27/95	06/27/25	10,000,000	SU	588,119	9,411,881	7.18%
8	6.42% Series E	07/07/97	07/07/27	5,000,000	SU	200,000	4,800,000	6.86%
9	6.68% Series E	07/07/97	07/07/27	1,000,000	SU	0	1,000,000	6.68%
10	6.34% Series F	12/09/97	12/10/27	20,000,000	SU	651,007	19,348,993	6.69%
11	6.36% Series F	05/04/98	05/01/28	10,000,000	SU	325,503	9,674,497	6.71%
12	6.55% Series F	06/30/98	06/30/28	20,000,000	SU	651,007	19,348,993	6.91%
13	7.08% Series G	10/05/99	10/05/29	30,000,000	SU	2,506,640	27,493,360	8.06%
14	6.625% Series (1)	11/27/01	12/01/11	98,954,060	SU	0	98,954,060	6.80%
15	5.45% Series (2)	11/21/05	12/01/15	24,716,007	SU	1,410,958	23,305,049	6.42%
16	5.75% Series (3)	07/24/03	08/01/18	37,128,275	SU	1,509,993	35,618,282	6.30%
17	6.10% Series (4)	11/21/05	12/01/35	50,568,961	SU	3,456,722	47,112,239	6.52%
18	5.95% Series (5)	10/18/06	10/01/36	32,470,349	SU	0	32,470,349	6.83%
19				$371,337,652		$13,010,678	$358,326,974	6.85%

20 **Annual Amortization Expense of Retired Notes**

21

22	**Long-Term Notes**	**Date of Issue**	**Retirement Date**	**Annual Amortization**	**Debt Outstanding**	**Divided by Outstanding**
23	5.75% Series F	01/24/98	01/15/03	32,284	$371,337,652	0.009%
24	6.36% Series F	12/05/97	12/06/04	32,541	$371,337,652	0.009%
					Total Effective Interest Rate	6.86%

(1) The coupon rate at the VUHI level is 6.625% on a gross amount of $100,000,000. Vectren North has an effective rate of 6.80% on the net amount of $98,954,060 in order to reimburse VUHI for the interest and amortization expense.

(2) The coupon rate at the VUHI level is 5.45% on a gross amount of $25,000,000. Vectren North has an effective rate of 5.63% on the net amount of $24,716,007 in order to reimburse VUHI for the interest and amortization expense.

(3) The coupon rate at the VUHI level is 5.75% on a gross amount of $37,500,000. Vectren North has an effective rate of 5.87% on the net amount of $37,128,275 in order to reimburse VUHI for the interest and amortization expense.

(4) The coupon rate at the VUHI level is 6.10% on a gross amount of $50,000,000. Vectren North has an effective rate of 5.99% on the net amount of $50,568,961 in order to reimburse VUHI for the interest and amortization expense.

(5) The coupon rate at the VUHI level is 5.95% on a gross amount of $35,000,000. Vectren North has an effective rate of 6.83% on the net amount of $32,470,349 in order to reimburse VUHI for the interest and amortization expense.

INDIANA GAS COMPANY, INC.

D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.

(VECTREN NORTH)

IURC CAUSE NO. 43298

DIRECT TESTIMONY

OF

DOUGLAS A. KARL

VICE PRESIDENT, MARKETING AND CUSTOMER SERVICE

ON

ENERGY EFFICIENCY

SPONSORING PETITIONER'S EXHIBITS NO. DAK-1 THROUGH DAK-4

DIRECT TESTIMONY OF DOUGLAS A. KARL

Q. Please state your name and business address.

A. My name is Douglas A. Karl, and my business address is One Vectren Square, Evansville, Indiana 47708.

Q. What position do you hold with Applicant Vectren North?

A. I am Vice President of Marketing and Customer Service. I also hold these same positions with Vectren Corporation ("Vectren"), Vectren Utility Holdings, Inc. ("VUHI"), Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery, Inc. ("Vectren South") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. Please describe your educational background.

A. In December 1974, I graduated from Bryant College, located in Smithfield, Rhode Island, with a Bachelor of Science Degree in Business Administration.

Q. Please describe your professional background.

A. From 1976 to 1988, I was employed at Providence Gas Company, serving through those years in a number of residential, commercial and industrial sales and marketing positions. From 1988 to 1990, I was Marketing Manager of International Fuel Cells Corporation, a Division of United Technologies Corporation, South Windsor, Connecticut. In February, 1990, I was hired by Vectren as Manager of Industrial Marketing. Subsequently, I have held the positions of Director of Industrial Marketing, Director of Industrial and Commercial Marketing, Director of Marketing and Sales, and Senior Director of Customer Service. On May 1, 2002, I was promoted to Vice President of Marketing and Customer Service.

Q. Please describe the responsibilities of your current position.

A. I am responsible for Vectren Energy's Customer Service functions including industrial, commercial, and residential marketing and sales activities. This includes interfacing with large commercial and industrial customers to respond to their energy service needs. My duties also include overseeing and participating in negotiations on behalf of Vectren Energy with industrial and large volume customers regarding their energy service requirements.

Q. Please summarize the purpose of your testimony in this Cause.

A. The purpose of my testimony is to explain the progress made on Vectren's natural gas efficiency efforts since the IURC authorized the Company to implement a two phase efficiency program for our residential and general service customer classes.

Q. What transpired leading up to the creation of Vectren's natural gas energy efficiency program?

A. On November 30, 2004, in Cause No. 42598, the IURC approved a settlement agreement between Vectren and several other parties that provided for the parties to the agreement to develop and implement a pilot plan which was administered by an independent third party and select a qualified consultant to perform a market potential study and recommendation of longer term, cost-effective efficiency programs. Under the settlement, Vectren agreed to spend up to $50,000 so that an independent and qualified consultant could be retained to initially develop a pilot plan for conservation programs to be implemented immediately. Vectren also agreed to initiate pilot programs which began in the summer of 2006. Vectren and the Collaborative consisting of the OUCC, CAC, and IGIG, issued an RFP and selected the Wisconsin Energy Conservation Corporation to prepare and administer the pilot programs. Apart from the roll out of pilot programs, Vectren also agreed to pay $100,000 for a long term Market Assessment and Action Plan. Vectren, with the Collaborative, issued an RFP and selected Forefront Economics and H. Gil Peach for this project.

The collaborative process continued through 2005 at a time when gas prices were especially volatile after the impact of several hurricanes. The Collaborative continued to build consensus on the terms for an efficiency program using knowledge gained from the pilot programs. In February of 2006, Vectren North filed the Market Assessment and Action Plan as required by the 2004 settlement. In Cause No. 43046, an Efficiency Settlement was eventually filed late in 2006 which resulted from the collaborative dialogue and the Market Assessment. The Settlement contained an Action Plan consisting of over $4 million of efficiency programs. Vectren has implemented Phase I of the Action Plan, which we refer to as the "Conservation Connection." Phase II of the Action Plan calls for the programs to be transitioned to an independent third party administrator.

Q. What are the specific elements of the Conservation Connection?

A. The Conservation Connection combines 7 key programs. The highlights of each program include:

- Residential Program. This component offers rebates for high efficiency technologies targeted at reducing space and water heater consumption. The rebates apply to the purchase and installation of high efficiency appliances and automatic setback programmable thermostats. A list of these rebates is provided in Petitioner's Exhibit DAK-2.

- Home Construction Program. This component targets new home builders to promote the incorporation of high efficiency design features and equipment in new homes. The rebates described above apply to this program, as well as a financial incentive of $1,000 to a builder of a new home that meets an energy efficiency rating such as the Energy Star Homebuilder Standard. A list of these rebates is provided in Petitioner's Exhibit DAK-2.

- Commercial/General Services Program. This component provides rebates to Vectren's business customers for installation of energy efficient furnaces, high-efficiency boilers, boiler tune-ups and control upgrades. The goal is to provide financial assistance to encourage replacement of older, inefficient equipment with new high-efficiency equipment. A list of these rebates is provided in Petitioner's Exhibit DAK-2.

- Special Needs Program. This program is similar to the Commercial/General Services program but is directed at non-profit organizations and non-post secondary schools.

- Targeted Income Program. This program is modeled after the pilot program which provides supplementary funding for the existing Weatherization Assistance Program (WAP). WAP provides whole house weatherization for customers with incomes up to 150% of the federal poverty guidelines. This program is designed to extend funding to provide weatherization assistance to customers with incomes up to 200% of the federal poverty guidelines.

- On-line Energy Audit and Bill Analysis Program. This element of the Online Program uses the Nexus Energy software and is a comprehensive internet-based interactive information system. It includes a customer bill analyzer, an easy to use on-line energy audit tool, comparative appliance calculators and an energy efficiency/conservation information library. These tools provide Vectren the ability to educate residential and small to medium sized commercial customers about how their behavior and appliance usage impacts their monthly bills.

- Outreach Campaign. To make the public aware of the programs, Vectren launched an aggressive media outreach campaign that included targeted mailings, television, radio and newspaper interviews, and company trained speakers addressing the community. Examples of these materials are provided in Petitioner's Exhibit DAK-3.

- Energy Resource Center (ERC). The ERC, known publicly as the Conservation Connection call center, is a customer service program staffed by dedicated customer service representatives knowledgeable about the conservation programs. These representatives provide referrals to rebate/incentive and weatherization programs, issue energy efficiency tips and assist customers with utilizing the Nexus Energy software system.

Q. How is Vectren measuring the results of the conservation program?

A. The results of the program are measured several ways. First, an Oversight Board consisting of representatives from Vectren, IURC, OUCC, the Lieutenant Governor's Indiana Energy Group, Energy Center at Discovery Park, Purdue University and the Alliance to Save Energy provides oversight of the programs within the Action Plan and evaluates the programs on an ongoing basis. In addition, the program will be evaluated against pertinent measures that focus on program costs and benefits achieved. Specifically, the Collaborative has determined that the appropriate evaluation measures during Phase I should include participation levels, energy savings, and gas supply cost savings. The Collaborative has reviewed and approved the use of a monthly scorecard report that Vectren administers and prepares as the means of providing conservation program results.

Q. Is the Program being implemented in all of Vectren's service territories, or just Vectren North?

A. Although the collaborative process started due to the settlement in the last Vectren North rate case, Vectren South has been included in the efficiency program because the company as a whole has undertaken a dramatic change in focus in order to become an advocate of conservation rather than increased usage. This change cannot be effectively limited to a single utility. It is also more efficient and effective in the short term as well as in the longer term to design common programs for both the utilities. Finally, the pertinent vendors and media outlets overlap the territories of both Vectren North and South and the ERC handles all Indiana customer inquires. Consequently, the impact of the program must be analyzed across both utilities to appreciate the impact it has had to this point.

Q. In Cause No. 43046, Vectren indicated it would change its corporate culture by embracing energy efficiency. Please describe what Vectren has done to accomplish this transformation?

A. Since the December 1, 2006 order, Vectren has proceeded to implement the following: the establishment of the ERC; Conservation Connection materials, including rebate pads, fact sheets and lists of qualifying products, mailed to 1,400 trade allies; 1500 speakers bureaus letters sent to legislators, community leaders and health and human services agencies, and non-profit social groups; 40 employee conservation training meetings for contact center, field operations and corporate employees (reaching approximately 1175 employees); and launching of the paid media outreach of TV, radio and newsprint materials.

In addition, a soft launch of the Nexus on-line tools was initiated in December. This means links to the tools were made available on the Company's website but not publicly promoted. Before releasing it publicly, Vectren's employees were encouraged to use the tool and provide feedback. To ramp-up to the launch of the Program, a media tour led by Niel Ellerbrook, Chairman, President, and CEO, Jeff Whiteside, Vice President of Corporate Communications and me to announce the approval of the conservation order and initiation of the conservation focused culture change was conducted. Media events were held in Indianapolis, Terre Haute and Evansville. At the same time, a "cultural change" tour was commenced via employee face-to-face meetings where approximately 1175 employees where given materials to assist with responding to customer questions about how to conserve. All employees were given the materials although for those who could not attend one of the face-to-face meetings, supervisors and managers were directed to provide access to the meeting presentations and distribution of conservation materials. These materials included business cards, truck pads (tear sheets) with the toll free number for the Conservation Connection contact center and directions about finding rebate information and energy savings tips on www.vectren.com

In addition to these efforts, thirteen Speakers' Bureau Presentations have been given to approximately 270 people since March 31. TV commercials began the week of January 22 and ran through the first week of April. Radio spots ran for two weeks in February in conjunction with the Free Standing Insert that was circulated in approximately 500,000 Thursday newspapers. In January, the Wisconsin Energy Conservation Corporation (WECC) recruited two field representatives to conduct face to face training and raise awareness and continue promoting the program with distributors, contractors and retailers throughout the first phase of the program. Since March 31, WECC has made over 230 contacts. Vectren's residential sales staff has also been promoting the Conservation Connection programs through their relationships with home builders, food service outlets and heating and air contractors. To date, the 9-person staff has more than 275 contacts, including six presentations to various home builders associations.

Additional program promotional efforts include:

- eMarketing – a February email to all registered www.Vectren.com users to highlight the key elements of the Conservation Connection program. This email was issued to more than 200,000 customers.
- On-hold messages – messages were incorporated into our 1-800-227-1376 queue to highlight Conservation Connection rebates, energy efficiency tips and online tools.
- New bill insert design – the Indiana bill insert has been renamed "Conservation Connection." In January and February these inserts highlighted rebates, energy efficiency tips, the new call center and online tools.
- New fact sheets – new material has been created to highlight specific appliances such as a water heater or furnace and detail why customers should choose a high-efficiency unit. These fact sheets feature cost-savings by choosing high-efficiency equipment and energy efficiency tips. These are used with home builders, heating and air contractors, home show events and are available online.
- Appliance static clings – Rebate promotional material was created as a point of purchase material. WECC is working to get these items placed directly on qualifying appliances and thermostats in retail outlets.
- Leveraging existing sponsorships – by using existing sponsorships, we are further promoting Conservation Connection. Examples include radio spots on the Indianapolis Colts radio network, conservation PSA's on PBS affiliates and 30-second ads and web banner ads on Inside Indiana

Business.

- Other employee communications – We have included the Conservation Connection program in our corporate goals video and written plan and include a regular Conservation Connection update in our employee newsletter and Intranet site.

Finally, an agreement was entered into with Wisconsin Energy Conservation Corporation to provide assistance with rebate fulfillment; energy savings assessments for items not Energy Star® approved but recommended in the Vectren North Market Assessment and Recommended Action Plan; material development and distribution; training and awareness visits with trade allies and retail chains; and Quality Assurance services for furnace, water heater and boilers.

Q. What has been the impact of these efforts?

A. In January the Nexus on-line tools were prominently displayed on the web site and included in all paid media outreach. Since December there have been nearly 29,000 unique (first-time) users, and more than 10,200 of those visitors have visited more than once to employ either the Energy Audit or Bill Analyzer tool. Nearly 2,400 customers have signed up to receive an EnergyGram which is a quarterly email sent to customers informing them of specific energy tips. An online survey included with the first EnergyGram in March, in which nearly 400 people responded, concluded that nearly 80% found the Energy Audit tool helpful in identifying opportunities for energy savings and nearly 90% plan to implement some of the energy savings tips that were provided.

The rebate program began simultaneously with the Order. Therefore, any appliances or equipment qualified, purchased and installed on or after December 1, 2006 were accepted for rebate redemption. To date, there have been 1,775 residential, 41 new construction, and 41 commercial rebate redemptions. This equates to more than $260,000 in rebates. We estimate the therm savings from these rebates to be nearly 110,000 annually. In addition, the call center has logged nearly 10,000 calls since its inception.

Attached as Petitioner's Exhibit DAK-4 are "scorecards" which track the Indiana Conservation Connection results on a monthly basis.

Q. Is Vectren satisfied with the results of the Program thus far?

A. Yes. Given that we started the paid media outreach campaign in late January/early February and we had such a mild winter, participation levels and survey results of the key programs are promising. While we expect this summer's activity will likely dip, we are working to maintain momentum, both internally and externally, and will incorporate a multi-pronged communications strategy throughout the year to keep Conservation Connection at the forefront of our daily interaction with customers.

Throughout the summer, Vectren will promote the Conservation Connection through existing sponsorships, home show events, speaking engagements and earned media efforts and continued face to face meetings with builders, contractors and distributors. The paid media outreach campaign will resume in the fall and should coincide with Vectren's annual winter bill projections news conference in early October.

Despite the successes so far, there is more work to do. Initially, this is a five-year effort in collaboration with the Indiana Utility Regulatory Commission and the Indiana Office of the Utility Consumer Counselor and is not something that is intended to be short term in nature. Now just four months old, the program has yielded positive results and driven customers to take action.

Q. What is the status of Phase II of the Program which mandates the hiring of an independent third party to administer the Program?

A. The Oversight Board has unanimously selected a non-voting member, The Alliance to Save Energy (ASE) to develop and administer the bidding process for the third party administrator. ASE is a national, nonprofit, bipartisan public-policy organization that works in strategic partnership with businesses, government, environmental, educational and consumer lenders to promote the efficient use of energy worldwide. With their expertise and vast relationships throughout the energy efficiency industry a wide net will be cast for candidate recruiting. A pre-solicitation notice was distributed at the Washington, D.C. conference on Energy Efficiency Market Transformation in mid-April with the official release scheduled for May 2007. A bidders conference will also be scheduled in May. The Collaborative is optimistic that the final selection will occur in August with a smooth transition plan to ensue thereafter.

Q. What impact does the adoption of the Conservation Rider, or decoupling mechanism, have on Vectren's conservation program?

A. The adoption of the decoupling mechanism has allowed Vectren to institute a wholesale cultural change from one that relied on consumption to support fixed cost recovery to one that encourages conservation. Each Vectren employee, particularly those with direct customer contact, has been encouraged to promote conservation. As previously stated, we as a Company have promoted this cultural shift via internal communications, truck pads, the Vectren news network, weekly meetings, and formal training. From the CEO down, the Company has embraced efficiency and is actively spreading the message.

Q. Does Vectren need additional resources to manage its conservation and efficiency programs as they transition to Phase II of the Program?

A. Yes. To date, a manager and I have worked for the last few years to get our efficiency efforts off the ground in two states. We work with consultants and contractors to advance the efforts. Given our ongoing commitment to these efforts, we intend to hire a Director of Marketing/Energy Efficiency Services. This person will primarily be responsible for development, implementation and management oversight of the company's electric and natural gas conservation and energy efficiency programs, including all renewable power programs and low-income weatherization programs. This employee will lead the regulatory coordination of these electric and natural gas conservation programs, including management of the regulatory collaborative process; coordination of all necessary program evaluations and program reporting requirements. In addition, this person will lead the Company's residential and commercial customer addition activities in coordination with the conservation strategies and programs.

Q. What is the pro forma expense associated with adding this Director?

A. The Vectren North operations allocated annual cost impact is $100,136 and is included in Petitioner's Exhibit MSH-3, Adjustment A17, page 2 of 2 (line 20).

Q: Apart from your efficiency responsibilities, do you continue to oversee larger customer relationships?

A: Yes.

Q. Does Vectren North need to enhance its commercial sales group?

A. Yes, Vectren plans to add a Field Sales Representative to support Vectren North's growing number of commercial accounts. This position provides direct account support for business clients within their assigned areas of responsibility. Responsibilities include customer service, relationship building, facilitation of facilities installations, resolution of billing issues, and providing basic economic development and community relations support.

Q. What is the pro forma expense associated with adding this position?

A. The Field Sales Representative has an allocated annual cost impact to Vectren North of $65,520 and is included in Petitioner's Exhibit MSH-3, Adjustment A17, page 2 of 2 (line 42).

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

VECTREN Energy Delivery
Conservation Connection

Application for Residential Appliance/Product Rebates

Rebate Requirements

1. Applicant must be a Vectren Energy Delivery of Indiana natural gas customer and location of installed equipment must have Vectren natural gas service.
2. All applicable fields must be completed on the form to receive a rebate (installation address is required).
3. **A copy of the customer's invoice(s) must be stapled to the back of this form.**
4. The new appliance/product must have been purchased on or after December 1, 2006.
5. The rebate form and invoice(s) must be postmarked within 30 days of the appliance/product installation. (Rebate funds are limited and available on a first-come, first-served basis.)
6. An eligible customer may receive a rebate for each eligible appliance/product installed.
7. Please allow up to eight (8) weeks to receive your rebate. Incomplete rebate forms will not be processed.
8. Mail the completed form and invoice to:
   Vectren Energy Delivery of Indiana
   Attn: Rebates
   P.O. Box 3552
   Evansville, IN 47734-3552

Customer Information

First Name: ______________________ Last Name: ______________________

Phone: ______________________ E-mail Address: ______________________

Mailing Address: ______________________ Address of Installation: (if different from mailing) ______________________

City: ____________ State: ____ Zip: ________ City: ____________ State: ____ Zip: ________

Appliance/Product and Contractor Information

Business from which appliance/product was purchased: ______________________ Phone: ____________

Installed Equipment	Rebate	Brand and Model Number	Serial Number	Date Installed	Quantity
Natural gas furnace — must be 90% AFUE or higher	$250				
Natural gas water heater — must be 0.62 EF or higher and 30 gallons or more	$50				
Programmable thermostat* — must be ENERGY STAR® qualified	$20*				
Clothes washer** — must be ENERGY STAR qualified	$100**				
Clothes washer# — must be ENERGY STAR qualified **and** matching natural gas dryer	$130#				

** Applicant must use natural gas space heating to receive the thermostat rebate.*
*** Applicant must utilize a natural gas water heater to receive the clothes washer rebate. Applicant who uses an electric water heater does not qualify.*
 # Applicant cannot apply for both the $100 clothes washer rebate and the $130 clothes washer and matching natural gas dryer rebate. Applicant must provide manufacturer's specifications showing that the washer and dryer are a matching set.

If replacing an existing appliance/product, please provide the age and brand, if known.

Appliance: ____________ Model: ______________________ Year: ________

Appliance: ____________ Model: ______________________ Year: ________

see reverse side for required signature and terms and conditions

This completed form and a copy of the invoice(s) must be provided to receive a rebate(s). I certify that I have purchased the product(s) indicated on this form, and the unit(s) was installed at the address indicated. I understand that random inspections may be conducted to verify installation according to the terms and conditions. I have read and understand the general eligibility, terms and conditions associated with this program. I am providing the requested information solely to be eligible to participate in this program and request that the personal information supplied by me be treated as confidential to the maximum extent possible. I acknowledge and agree that Vectren Energy Delivery is not warranting any equipment, nor will it be liable for any personal injury or property damage caused by the equipment.

Customer's Signature: ______________________________ Date: ______________

Terms and Conditions

General Eligibility: For a current list of qualifying equipment, visit www.vectren.com or call 1-866-240-8476. This offer provides rebates for the purchase of new, installed qualifying products and/or services, and is not dependent on the purchase of any other product or service unless indicated (i.e the clothes washer and natural gas dryer must be purchased as a pair to receive the $130 rebate). Offer valid for Vectren Energy Delivery of Indiana natural gas residential customers only. The rebates on this form are available to residential homes or rental buildings of three units or less only. Customers cannot apply for a residential rebate and a new home construction rebate on the same appliance or product. One form must be completed for each address in which appliance(s)/product(s) is installed. Vectren rebate cannot exceed the cost of the equipment or service.

Verification: Vectren Energy Delivery of Indiana reserves the right to verify sales receipts and/or installations of products and services before issuing rebates. A random inspection may be conducted to verify installations.

Program Modifications: Vectren Energy Delivery of Indiana reserves the right to alter or discontinue these rebate offers at any time without notice. Rebate funds are limited and are available on a first-come, first-served basis.

Disclaimer: Vectren Energy Delivery of Indiana does not guarantee that energy efficiency measures purchased and installed or services provided through this program will result in energy and costs savings. Vectren Energy Delivery of Indiana reserves the right to deny or limit any rebate request. In addition, no warranties on product or service installations are provided by Vectren Energy Delivery of Indiana, nor does the program warranty, guarantee or endorse the energy efficiency services provided by any specific contractor participating in the program. Please allow up to eight (8) weeks to receive your rebate.

Eligibility Dates: This rebate form is only eligible for qualified installations performed on or after December 1, 2006. All forms must be postmarked within 30 days of installation to be considered eligible for rebates. Vectren Energy Delivery of Indiana reserves the right to alter or discontinue this program or related rebates at any time without notice.

Contractor Instructions:
Verify that customer's natural gas utility at the installation address is Vectren Energy Delivery of Indiana.

High Efficiency Natural Gas Furnace and/or Water Heater: Installers are required to implement the following measures to qualify furnace and/or water heater installations for rebates:

> Chimney liners must be installed where atmospherically-drafted equipment remains in the residence.
>
> Installers must complete flue closure protocol where a high efficiency furnace and/or water heater is installed and the chimney has no other use; where the water heater is power vented through the sidewall or is fueled by electricity (refer to flue closure protocol);
>
> The furnace must be a sealed combustion unit with combustion air supply provided from outside the home to reduce whole-house air infiltration.

This form has no cash value.

Please retain a copy for your records.

VECTREN Energy Delivery | Conservation Connection

Application for New Home Construction Rebates

Rebate Requirements

1. Address of installed equipment must have Vectren Energy Delivery of Indiana natural gas service.
2. All applicable fields must be completed on the form to receive a rebate (installation address is required).
3. **A copy of the builder's invoice(s) and/or ENERGY STAR® rating certificate must be stapled to the back of this form.**
4. The new appliance/service(s) must have been purchased and the request for gas line installation must have occurred on or after December 1, 2006.
5. The rebate form and invoice(s) must be postmarked within 30 days of the completion of home construction. (Rebate funds are limited and available on a first-come, first-served basis.)
6. An eligible builder may receive a rebate for each eligible appliance/service installed or provided.
8. Please allow up to eight (8) weeks to receive your rebate. Incomplete rebate forms will not be processed.
9. Mail the completed form and invoice to:
   Vectren Energy Delivery of Indiana
   Attn: Rebates
   P.O. Box 3552
   Evansville, IN 47734-3552

Home Builder Information

Company Name: ______________________ Contact Name: ______________________

Phone: ______________________ E-mail Address: ______________________

Mailing Address: ______________________ Address of Installation: (if different from mailing) ______________________

City: ______________ State: ____ Zip: ________ City: ______________ State: ____ Zip: ________

Appliance/Service Information

Installed Equipment and/or Service Provided	Rebate	Brand and Model Number	Serial Number	Date Installed	Quantity
Natural gas furnace* — must be 90% AFUE or higher	$250*				
Natural gas water heater — must be 0.62 EF or higher and 30 gallons or more	$50				
Programmable thermostat* — must be ENERGY STAR qualified	$20*				
Clothes washer** — must be ENERGY STAR qualified	$100**				
Clothes washer** — must be ENERGY STAR qualified **and** matching natural gas dryer	$130**				
Adoption of ENERGY STAR standards# — Home must be ENERGY STAR certified	$1,000#	Builder must submit a copy of an authorized ENERGY STAR new home energy rating certificate from an authorized ENERGY STAR provider/rater.			

** Home must utilize natural gas for all space heating needs.*
*** Home must utilize natural gas for all water heating needs. Applicant cannot apply for both the $100 clothes washer rebate and the $130 clothes washer and matching natural gas dryer rebate. Applicant must provide manufacturer's specifications showing that the washer and dryer are a matching set.*
 # Home must utilize natural gas for all water and space heating needs. There is a maximum of 20 ENERGY STAR home rebates per builder per calendar year. Natural gas furnace must be minimum 90% AFUE and natural gas water heater must be 0.62 EF or greater.

see reverse side for required signature and terms and conditions

This completed form and a copy of the invoice(s) must be provided to receive a rebate(s). I certify that I have purchased the product(s) and/or service(s) indicated on this form, and the product(s) was installed at the address indicated. I understand that random inspections may be conducted to verify installation according to the terms and conditions. I have read and understand the general eligibility, terms and conditions associated with this program. I am providing the requested information solely to be eligible to participate in this program and request that the personal information supplied by me be treated as confidential to the maximum extent possible. I acknowledge and agree that Vectren Energy Delivery is not warranting any equipment, nor will it be liable for any personal injury or property damage caused by the equipment.

Builder's Signature: ______________________________ Date: ______________

Terms and Conditions

General Eligibility: For a current list of qualifying equipment, visit www.vectren.com or call 1-800-227-1376, select the English or Spanish option and the select Option 6. This offer provides rebates for the purchase of new installed qualifying products and/or services, and is not dependent on the purchase of any other product or service unless indicated (i.e the clothes washer and natural gas dryer must be purchased as a pair to receive the $130 rebate). There is a maximum of 20 ENERGY STAR home rebates per builder per calendar year. Offer valid for home builders constructing a natural gas home in the Vectren Energy Delivery of Indiana natural gas service territory. The rebates on this form are available to single-family residential homes only. Builders cannot apply for a residential rebate and a new home construction rebate on the same appliance or product. Vectren rebate cannot exceed the cost of the equipment or service.

Verification: Vectren Energy Delivery of Indiana reserves the right to verify sales receipts and/or installations of products and services and that the equipment installed meets program requirements before issuing rebates. A random inspection may be conducted to verify installations.

Program Modifications: Vectren Energy Delivery of Indiana reserves the right to alter or discontinue these rebate offers at any time without notice. Rebate funds are limited and are available on a first-come, first-served basis.

Disclaimer: Vectren Energy Delivery of Indiana does not guarantee that energy efficiency measures purchased and installed or services provided through this program will result in energy and costs savings. Vectren Energy Delivery of Indiana reserves the right to deny or limit any rebate request. In addition, no warranties on product or service installations are provided by Vectren Energy Delivery of Indiana, nor does the program warranty, guarantee or endorse the energy efficiency services provided by any specific contractor participating in the program. Please allow up to eight (8) weeks to receive your rebate.

Eligibility Dates: This rebate form is only eligible for qualified installations/services performed on or after December 1, 2006. All forms must be postmarked within 30 days of home completion to be considered eligible for rebates. Vectren Energy Delivery of Indiana reserves the right to alter or discontinue this program or related rebates at any time without notice.

Contractor Instructions: Verify that natural gas utility at the installation address is Vectren Energy Delivery of Indiana.

High Efficiency Natural Gas Furnace: Installers are required to verify that the furnace must be a sealed combustion unit with combustion air supply provided from outside the home to reduce whole-house air infiltration.

This form has no cash value.

Please retain a copy for your records.

VECTREN Energy Delivery

ConservationConnection

Application for Commercial Rebates

Rebate Requirements

1. Applicant must be a Vectren Energy Delivery of Indiana commercial natural gas customer and location of installed equipment or services performed must have Vectren natural gas service.
2. All applicable fields must be completed on the form to receive a rebate (installation address is required).
3. **A copy of the customer's invoice(s) must be stapled to the back of this form.**
4. The new equipment must have been purchased or the tune-up must have been performed on or after December 1, 2006.
5. The rebate form and invoice(s) must be postmarked within 30 days of the equipment installation or service. (Rebate funds are limited and available on a first-come, first-served basis.)
6. An eligible customer may receive a rebate for each eligible piece of equipment installed or service performed.
7. Please allow up to eight (8) weeks to receive your rebate. Incomplete rebate forms will not be processed.
8. Mail the completed form and invoice to:
   Vectren Energy Delivery of Indiana
   Attn: Rebates
   P.O. Box 3552
   Evansville, IN 47734-3552

Customer Information

Business Name: ______________________ Contact Name: ______________________

Phone: ______________________ E-mail Address: ______________________ Federal Tax ID: __ __ - __ __ __ __ __ __ __

Mailing Address: ______________________ Address of Installation: (if different from mailing) ______________________

City: ______________ State: ___ Zip: ________ City: ______________ State: ___ Zip: ________

Type of Business: (check one) ___ Corporation ___ Partnership ___ Sole Proprietorship ___ Other ___ Exempt

Equipment Information

Installed Equipment	Rebate	Brand and Model Number	Serial Number	Date Installed	Quantity
Natural gas furnace — 90% AFUE or higher	$250				
Natural gas storage water heater — 75,000 Btu/hr or greater, 88% thermal efficiency	$150				
Natural gas boiler* — 90% AFUE (less or equal to 300,000 Btu/hour input) / 90% combustion efficiency (greater than 300,000 Btu/hour input)	$350 to $5,000*				
Natural gas boiler reset control (retrofit only)	$250				
Natural gas boiler modulating burner control** — minimum turndown ratio of 5 to 1 (retrofit only)	Up to $2,500**				
Natural gas boiler modulating burner control** — minimum turndown ratio of 10 to 1 (retrofit only)	Up to $5,000**				

**Vectren rebate may be up to 25% of the purchase price, excluding tax and installation costs, but will not exceed the maximum rebate amount. Must provide a copy of the manufacturer's cut-sheet, which must include the combustion efficiency or AFUE rating.*
*** Vectren rebate may be up to 25% of the purchase price excluding tax and installation costs but will not exceed the maximum rebate amount.*

see reverse side for required signatures and terms and conditions

Boiler Tune-Up* - $250 Rebate

Contractor performing tune-up: ______________________________ Phone: __________

Boiler Details (model and serial number)	Combustion efficiency	Stack Temp	O_2	CO_2	CO	Tune-Up Cost	Tune-Up Date
	Pre: Post:	Pre: Post:	Pre: Post:	Pre: Post:	Pre: Post:		
	Pre: Post:	Pre: Post:	Pre: Post:	Pre: Post:	Pre: Post:		

**Vectren rebate not to exceed tune-up cost.*

This completed form and a copy of the invoice(s) must be provided to receive a rebate(s). I certify that I have purchased the equipment and/or service(s) indicated on this form, and the unit(s) was installed or the services were performed at the address indicated. I understand that random inspections may be conducted to verify services performed according to the terms and conditions. I have read and understand the general eligibility, terms and conditions associated with this program. I am providing the requested information solely to be eligible to participate in this program and request that the personal information supplied by me be treated as confidential to the maximum extent possible. I acknowledge and agree that Vectren Energy Delivery is not warranting any equipment, nor will it be liable for any personal injury or property damage caused by the equipment.

Customer's Signature: ______________________________ Date: __________

Business from which appliance/product was purchased: ______________________________ Phone: __________

Contractor's Signature: ______________________________ Date: __________

Terms and Conditions

General Eligibility: For a current list of qualifying equipment, visit www.vectren.com or call 1-866-240-8476. This offer provides rebates for the purchase and performance of new qualifying equipment and/or services and is not dependent on the purchase of any other product or service unless indicated. Offer valid for Vectren Energy Delivery of Indiana natural gas commercial customers only. Qualifying commercial accounts include rate 220 in Vectren Energy Delivery of Indiana North and rate 120 in Vectren Energy Delivery of Indiana South. Limit one tune-up service per boiler every two years. Vectren rebate cannot exceed the cost of the equipment or service.
Verification: Vectren Energy Delivery of Indiana reserves the right to verify sales receipts of equipment purchased and/or services performed before issuing rebates. A random inspection may be conducted to verify installations.
Program Modifications: Vectren Energy Delivery of Indiana reserves the right to alter or discontinue these rebate offers at any time without notice. Rebate funds are limited and are available on a first-come, first-served basis.
Disclaimer: Vectren Energy Delivery of Indiana does not guarantee that energy efficiency measures purchased and installed or services provided through this program will result in energy and costs savings. Vectren Energy Delivery of Indiana reserves the right to deny or limit any rebate request. In addition, no warranties on product or service installations are provided by Vectren Energy Delivery of Indiana, nor does the program warranty, guarantee or endorse the energy efficiency services provided by any specific contractor participating in the program. Please allow up to eight (8) weeks to receive your rebate.
Eligibility Dates: This rebate form is only eligible for equipment purchased or qualified tune-ups performed on or after December 1, 2006. All forms must be postmarked within 30 days of installation or services performed to be considered eligible for rebates. Vectren Energy Delivery of Indiana reserves the right to alter or discontinue this program or related rebates at any time without notice.
Taxes: Incentives are taxable and if greater than $600 will be reported to the IRS unless you are exempt. Vectren Energy Delivery of Indiana will report your rebate as income to you on IRS Form 1099 unless you have checked corporation or exempt status above. You are urged to consult your tax advisor concerning the taxability of rebates. Vectren Energy Delivery of Indiana is not responsible for any taxes that may be imposed on your business as a result of your receipt of this rebate.

This form has no cash value. **Please retain a copy for your records.**

VECTREN Energy Delivery | Conservation Connection

Application for Commercial Food Service Rebates

Rebate Requirements

1. Applicant must be a Vectren Energy Delivery of Indiana commercial natural gas customer and location of installed equipment must have Vectren natural gas service.
2. All applicable fields must be completed on the form to receive a rebate (installation address is required).
3. **A copy of the customer's invoice(s) must be stapled to the back of this form.**
4. The new equipment must have been purchased on or after December 1, 2006.
5. The rebate form and invoice(s) must be postmarked within 30 days of the equipment installation. (Rebate funds are limited and available on a first-come, first-served basis.)
6. An eligible customer may receive a rebate for each eligible piece of equipment installed.
7. Please allow up to eight (8) weeks to receive your rebate. Incomplete rebate forms will not be processed.
8. Mail the completed form and invoice to:
   Vectren Energy Delivery of Indiana
   Attn: Rebates
   P.O. Box 3552
   Evansville, IN 47734-3552

Equipment Information

Installed Equipment	Rebate	Brand and Model Number	Serial Number	Date Installed	Quantity
Natural gas fryer — must be ENERGY STAR® qualified	$300				
Natural gas griddle — minimum cooking energy efficiency rating of 38%	$100				
Natural gas convection/ conveyor oven — minimum cooking energy efficiency rating of 40%, thermostatic control	$250				
Natural gas booster water* heater — 80% thermal efficiency or higher	$500*				
Natural gas combination oven — minimum cooking energy efficiency rating of 40%, thermostatic control	$1,000				
Natural gas infrared upright broiler*	$600*				
Natural gas infrared charbroiler*	$200*				

** Must provide a copy of the manufacturer's cut-sheet.*

☐ New Business Installation (please check one) **OR** ☐ Existing Business Installation - If replacing an existing appliance, please provide the age and brand, if known.

Appliance: ______________ Model: ________________________ Year: __________

Appliance: ______________ Model: ________________________ Year: __________

Appliance: ______________ Model: ________________________ Year: __________

see reverse side for required customer signature and terms and conditions

Customer Information

Federal Tax ID: __ __ - __ __ __ __ __ __ __

Business Name: ____________________ Contact Name: ____________________

Phone: ____________________ E-mail Address: ____________________

Mailing Address: ____________________ Address of Installation: (if different from mailing) ____________________

City: ____________ State: ___ Zip: ________ City: ____________ State: ___ Zip: ________

Type of Business: (check one) ___ Corporation ___ Partnership ___ Sole Proprietorship ___ Other ___ Exempt

This completed form and a copy of the invoice(s) must be provided to receive a rebate(s). I certify that I have purchased the equipment and/or service(s) indicated on this form, and the unit(s) was installed or the services were performed at the address indicated. I understand that random inspections may be conducted to verify services performed according to the terms and conditions. I have read and understand the general eligibility, terms and conditions associated with this program. I am providing the requested information solely to be eligible to participate in this program and request that the personal information supplied by me be treated as confidential to the maximum extent possible. I acknowledge and agree that Vectren Energy Delivery is not warranting any equipment, nor will it be liable for any personal injury or property damage caused by the equipment.

Customer's Signature: ____________________ Date: ____________

Business from which equipment was purchased: ____________________ Phone: ____________

Contractor's Signature: ____________________ Date: ____________

Terms and Conditions

General Eligibility: For a current list of qualifying equipment, visit www.vectren.com or call 1-866-240-8476. This offer provides rebates for the purchase of new, installed qualifying equipment and is not dependent on the purchase of any other equipment unless indicated. Offer valid for Vectren Energy Delivery of Indiana natural gas commercial customers only. Qualifying commercial accounts include rate 220 in Vectren Energy Delivery of Indiana North and rate 120 in Vectren Energy Delivery of Indiana South. Vectren rebate cannot exceed the cost of the equipment.

Verification: Vectren Energy Delivery of Indiana reserves the right to verify sales receipts and/or installations of equipment and that the equipment installed meets program requirements before issuing rebates. A random inspection may be conducted to verify installations.

Program Modifications: Vectren Energy Delivery of Indiana reserves the right to alter or discontinue these rebate offers at any time without notice. Rebate funds are limited and are available on a first-come, first-served basis.

Disclaimer: Vectren Energy Delivery of Indiana does not guarantee that energy efficiency equipment purchased and installed or services provided through this program will result in energy and costs savings. Vectren Energy Delivery of Indiana reserves the right to deny or limit any rebate request. In addition, no warranties on product or service installations are provided by Vectren Energy Delivery of Indiana, nor does the program warranty, guarantee or endorse the energy efficiency services provided by any specific contractor participating in the program. Please allow up to eight (8) weeks to receive your rebate.

Eligibility Dates: This rebate form is only eligible for qualified installations performed on or after December 1, 2006. All forms must be postmarked within 30 days of installation to be considered eligible for rebates. Vectren Energy Delivery of Indiana reserves the right to alter or discontinue this program or related rebates at any time without notice.

Taxes: Incentives are taxable and if greater than $600 will be reported to the IRS unless you are exempt. Vectren Energy Delivery of Indiana will report your rebate as income to you on IRS Form 1099 unless you have checked corporation or exempt status above. You are urged to consult your tax advisor concerning the taxability of rebates. Vectren Energy Delivery of Indiana is not responsible for any taxes that may be imposed on your business as a result of your receipt of this rebate.

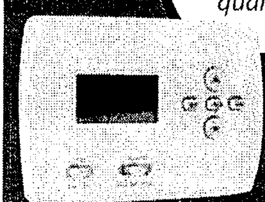
Contractor Instructions: Verify that customer's natural gas utility at the installation address is Vectren Energy Delivery of Indiana.

This form has no cash value. **Please retain a copy for your records.**

VECTREN

$20 MAIL-IN REBATE

on an ENERGY STAR® qualified programmable thermostat



ENERGY STAR

Customer name ______________________

Street address ______________________

City/Town ______________________

State, Zip ______________________

Phone ______________________

Email ______________________

Name of store where purchased ______________________

City, State ______________________

Address of Installation (if different than mailing)

Street address ______________________

City/Town ______________________

State, Zip ______________________

Please fill in the quantity, manufacturer and model of the product(s) purchased:

Quantity	Manufacturer	Model

Total number purchased ______________________

X $20 = **Total Rebate** ______________________

Limit 4 products per customer.

To receive rebate, follow all directions on the back of this form.

I am providing the requested information solely to be eligible to participate in this program and request that the personal information supplied by me be treated as confidential to the maximum extent possible.

____

Signature

ConservationConnection

ENERGY STAR

To receive your Cash-Back Rebate:

1. Purchase up to four ENERGY STAR® qualified programmable thermostat.

2. Cut out the UPC code from each box and attach it to this completed form, along with a copy of the cash register receipt with the purchase price(s) circled.

Mail to: **Vectren Energy Delivery of Indiana**
Attn: Rebates
P.O. Box 3552
Evansville, IN 47734-3552

Important Information:

1. Applicant must be a Vectren Energy Delivery of Indiana natural gas customer and location of installed equipment must have Vectren natural gas service. Applicant must use natural gas space heating to receive the rebate. The rebate is available to residential homes or rental buildings of three units or less only.
2. All applicable fields must be completed on the form to receive a rebate (installation address is required).
3. **A copy of the customer's receipt(s) must be stapled with this form.**
4. The new, ENERGY STAR® qualified programmable thermostat must have been purchased and installed on or after December 1, 2006.
5. The rebate form and receipt(s) must be postmarked within 30 days of purchase and installation. (Rebate funds are limited and available on a first-come, first-served basis.) Vectren Energy Delivery of Indiana reserves the right to alter or discontinue this program or related rebates at any time without notice.
6. An eligible customer may receive a rebate for each eligible appliance/product installed. Limit four per customer.
7. Please allow up to eight (8) weeks to receive your rebate. Incomplete rebate forms will not be processed.
8. Mail the completed form and invoice to:
   Vectren Energy Delivery of Indiana
   Attn: Rebates
   P.O. Box 3552
   Evansville, IN 47734-3552

Verification:

Vectren reserves the right to verify sales receipts and/or installations of products before issuing rebates. A random inspection may be conducted to verify installations.

Program Modifications:

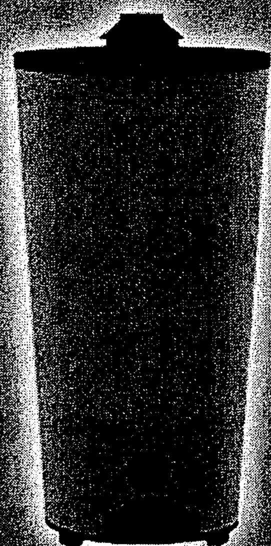
Vectren reserves the right to alter or discontinue this rebate offer at any time without notice. Rebate funds are limited and are available on a first-come, first-served basis.

Disclaimer:

Vectren does not guarantee that energy efficiency measures purchased and installed provided through this program will result in energy and costs savings. Vectren reserves the right to deny or limit any rebate request. In addition, no warranties on product installations are provided by Vectren, nor does the program warranty, guarantee or endorse the energy efficiency services provided by any specific contractor participating in the program. Please allow up to eight (8) weeks to receive your rebate.

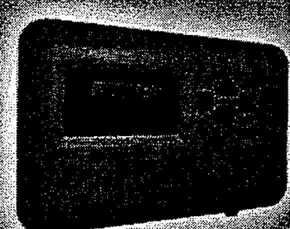
VECTREN
ConservationConnection

www.vectren.com 1-866-240-8476



Money Saving Tips to help manage your energy costs.

ConservationConnection



Inside

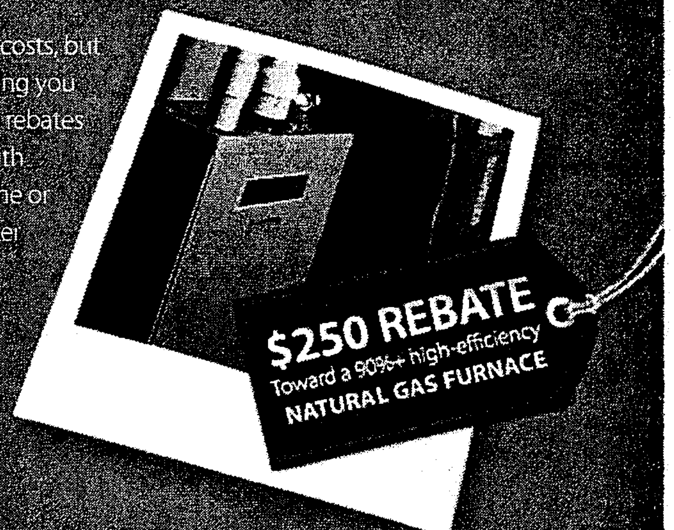
- Do-it-yourself tips for saving energy.
- Track your savings.
- Vectren rebates.

VECTREN

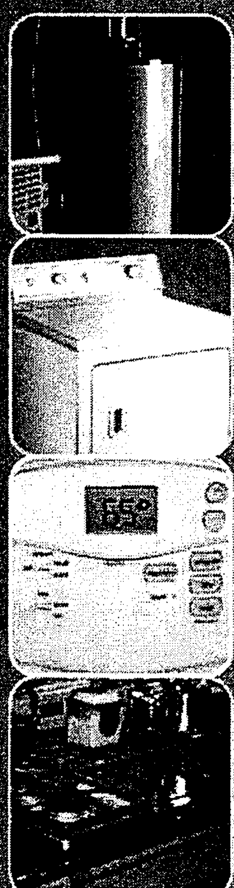
ConservationConnection

Check out these Vectren cash rebates on ENERGY STAR® furnaces, water heaters and select appliances.

Sure, you can turn down the thermostat to save on energy costs, but sometimes an old, inefficient appliance is what's really costing you money. Now, Vectren's Conservation Connection is offering rebates to save you even more when you replace old appliances with high-efficiency models or buy new appliances for your home or business. You'll get rebates for high-efficiency furnaces, water heaters, clothes washers, programmable thermostats and more. Just hang on to your receipt. Forms and instructions are available at www.vectren.com or by calling Vecten's Conservation Connection.



In addition, you may even qualify for some great ENERGY STAR® federal tax credits. Visit www.vectren.com or call 866.240.8476 to learn more.



RESIDENTIAL Rebates

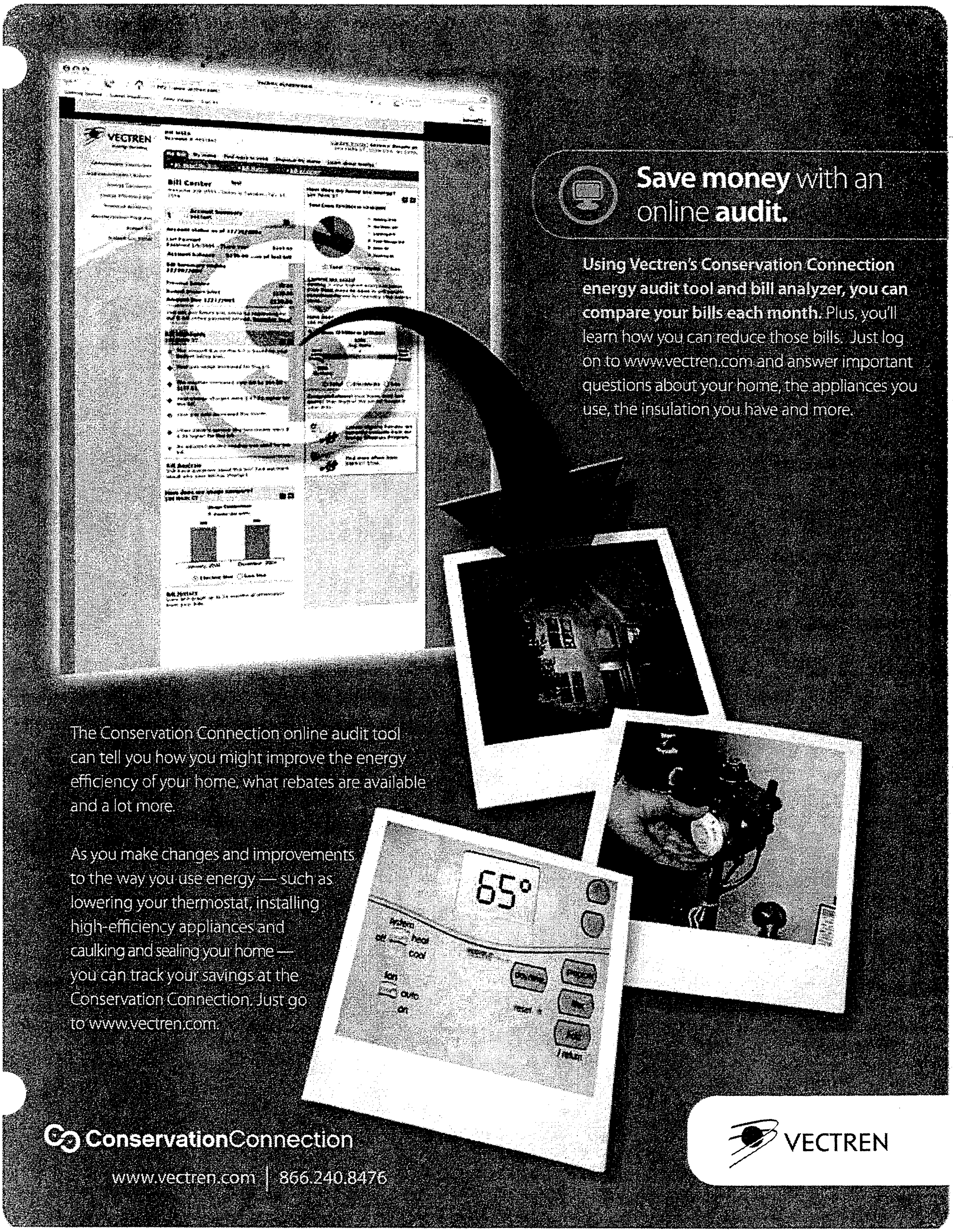
90%+ high-efficiency natural gas furnace	**$250**
ENERGY STAR clothes washer and matching natural gas dryer	**$130**
ENERGY STAR clothes washer	**$100**
High-efficiency, 30 gallon or more natural gas water heater (0.62 energy factor)	**$50**
ENERGY STAR programmable thermostat	**$20**

* Before buying, see complete details on appliance/service requirements at www.vectren.com.

COMMERCIAL Rebates

High-efficiency natural gas boilers	**Up to $5,000**
Natural gas boiler controls	**Up to $5,000**
Natural gas boiler tune-ups	**$250**
90%+ high-efficiency natural gas furnace	**$250**
High-efficiency natural gas water heater, 50 gal or more	**$150**
High-efficiency natural gas booster water heater	**$500**
ENERGY STAR qualified natural gas fryer	**$300**
High-efficiency natural gas griddle	**$100**
High-efficiency natural gas convection/conveyor oven	**$250**
High-efficiency natural gas combination oven	**$1,000**
Natural gas infrared upright broiler	**$600**
Natural gas infrared charbroiler	**$200**
New home builders adopting ENERGY STAR standards	**$1,000**

* Before buying, see complete details on appliance/service requirements at www.vectren.com.

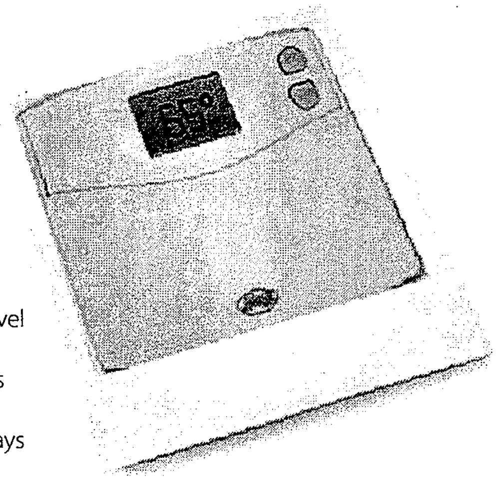

Save money with an online audit.
Using Vectren's Conservation Connection energy audit tool and bill analyzer, you can compare your bills each month. Plus, you'll learn how you can reduce those bills. Just log on to www.vectren.com and answer important questions about your home, the appliances you use, the insulation you have and more.
The Conservation Connection online audit tool can tell you how you might improve the energy efficiency of your home, what rebates are available and a lot more.
As you make changes and improvements to the way you use energy — such as lowering your thermostat, installing high-efficiency appliances and caulking and sealing your home — you can track your savings at the Conservation Connection. Just go to www.vectren.com.
65°
ConservationConnection
www.vectren.com | 866.240.8476
VECTREN

An inefficient house can cost a bundle. Here are nine quick and easy ways to help you manage energy costs and save some money.

ConservationConnection

Tip #1

Dial it down.



And install a programmable thermostat. You can save around five percent a year on your heating bills simply by turning your thermostat back five degrees for eight hours per day. A programmable thermostat is a great way to set your house on a temperature schedule automatically. When you use a programmable thermostat, you can lower the temperature while you sleep or when you're away. A programmable thermostat gradually brings the temperature to a comfortable level by morning or by the time you come home. An added benefit: Programmable thermostats can be inexpensive. Plus, it's easy to get money back through Vectren's Conservation Connection rebate program. Programmable thermostats are easy to install. Typically, it's as simple as connecting like-colored wires, but you should always refer to your owner's manual and installation guide.

Tip #2

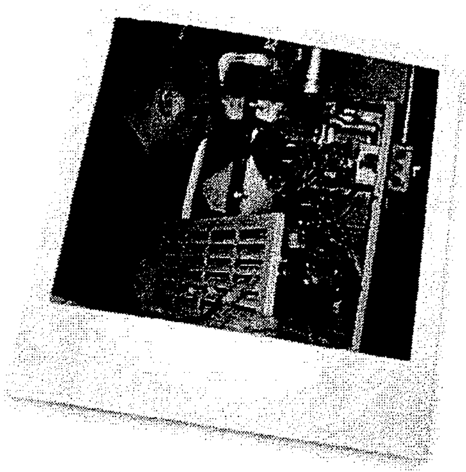
Strip it and **seal** it.

Stop the leaks. You know those small cracks around your doors and windows? You may not think they're a big deal, but sealing those air leaks has been shown to save up to 10 percent in heating costs. A caulking gun is easy to use once you get started, and you can finish weather-stripping your house in a day. Go to www.vectren.com to find a how-to guide for caulking and weather-stripping. You also can perform an online audit and discover other ways to reduce your energy bills.

Tip #3

Get it **inspected.**

Don't just let it run. Get the most out of your natural gas appliances by having them cleaned and inspected annually by a qualified technician. Appliances in tip-top condition will work more efficiently and use less energy.



Tip #4

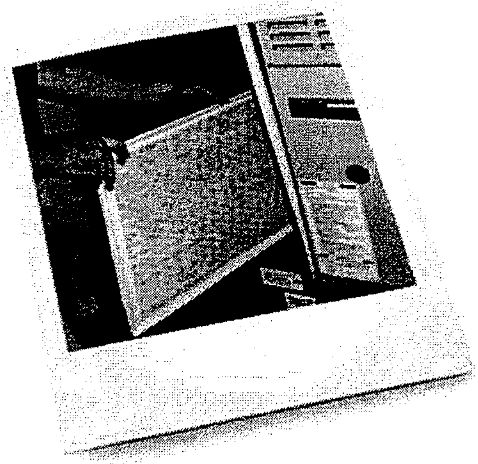
Use the sun.

And close the vents in rooms you don't use. Maximize the natural heat your house absorbs by keeping your drapes and blinds open during sunny days and retain the heat by keeping them closed at night. Also, make sure there's nothing covering your heating vents that can block the flow of warm air.

Tip #5

Insulate it.

Add layers and save. A well-insulated home keeps the warm air in and the cold air out. Adding another layer of insulation, whether it's to your exterior walls, floors or attic, will help reduce your heating costs and make your home more energy-efficient. You can roll batts of insulation between studs and joists or have insulation blown in by a contractor. Visit www.vectren.com for tips on how to properly insulate your home. You also can perform an online audit on other ways to reduce your heating bills this winter.



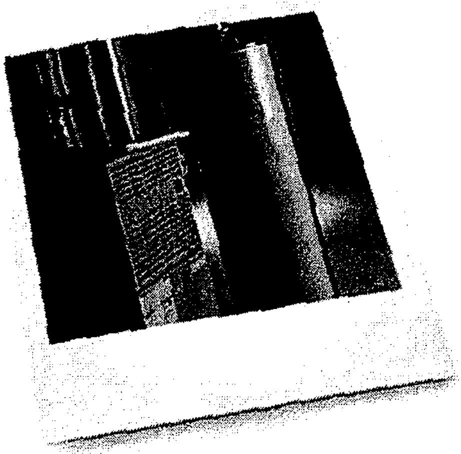
Tip #6

Change the filter.

Frequently. If you can't remember the last time you changed your filter, then you're probably due for a new one. Making that change translates to lower heating costs. Remember to replace your filter regularly as suggested by the manufacturer — it needs to be cleaned or changed in order to run efficiently and maintain clean air. For more information on ways to reduce your winter heating bills or to perform an online audit on your home's energy efficiency, visit www.vectren.com.

For more information, or to perform an online audit on the best ways to reduce your energy bills, visit www.vectren.com or call 866.240.8476.

VECTREN



Tip #7

Install high-efficiency natural gas appliances.

And save in the long run. If your furnace is more than 15 years old, it's probably only 60 to 70 percent efficient, and that's costing you money. A new furnace can significantly increase your efficiency and save you money in the long run. Vectren is making it easier than ever to replace your furnace by offering rebates on high-efficiency natural gas furnaces and other natural gas appliances.

Tip #8

Close your fireplace flue.

Don't let the cold in. Remember to shut the damper or flue on your fireplace when it's not in use. An open fireplace flue is like an open window that lets warm air escape through the chimney. For more information or to perform an online audit on the best ways to reduce your heating bills this winter, visit www.vectren.com.

Tip #9

Lower your water temperature.

We like to think of it as 10 degrees of separation. When you turn down your water heater thermostat just 10 degrees, you can save about 13 percent on water heating costs. A safe temperature setting is 120 degrees, which is typically hot enough for your daily household needs and cool enough to keep the water heater running efficiently. If you really want to save money, consider using cold water for laundry and other household tasks.

VECTREN

News Release

Vectren Corporation
One Vectren Square
Evansville, IN 47708

January 29, 2007
FOR IMMEDIATE RELEASE
Media contact: Mike Roeder, (812) 491-4143 or mroeder@vectren.com or
Chase Kelley (812) 491-4128 or kckelley@vectren.com

Vectren launches "Conservation Connection" to lower natural gas bills

Appliance rebates and new energy saving tools are now available to customers as Vectren Energy Delivery of Indiana (Vectren; NYSE: VVC) has launched a new, innovative program to help Indiana customers lower their total natural gas bills. Known as Conservation Connection, all Indiana residential and small commercial natural gas customers can take advantage of rebates on key appliances as well as online tools to perform energy audits and bill analysis to ultimately assist in lowering natural gas bills.

Approved Dec. 1, 2006, by the Indiana Utility Regulatory Commission (IURC), the program is part of a comprehensive Vectren conservation-oriented rate proposal that was the end product of an extended collaboration between Vectren and the Indiana Office of Utility Consumer Counselor (OUCC). In addition to providing conservation tools for customers, the program effectively breaks the linkage between the recovery of fixed service costs and the amount of customer usage, which positions Vectren to aggressively assist its customers to find ways to reduce their natural gas bills.

"This is a new day for our Indiana natural gas customers. The approval of the conservation program will enable us to squarely focus on helping our customers reduce usage and therefore save on their bills. This action is also important for our state and country as we continue to look for ways to reduce natural gas demand and increase supply," said Vectren Chairman, President and CEO Niel C. Ellerbrook. "This program provides customers the tools they need to individually implement energy efficiency measures and lower their usage. Since approximately 75 percent of each customer's bill is for the cost of gas they use, reducing consumption will produce significant savings."

The Conservation Connection tools include:

Conservation Connection Center:
- A unique contact center with a separate number (1-866-240-8476) that puts customers in touch with a conservation specialist to assist with energy efficiency tips, rebates and bill analysis.

Residential rebates toward energy efficient appliances/products:
- $250 toward a natural gas furnace (90%+ efficiency rating)
- $20 toward an ENERGY STAR® qualified programmable thermostat
- $50 toward a natural gas water heater (energy factor of 0.62% or higher)
- $130 toward an ENERGY STAR qualified washer and matching natural gas dryer

- more -

Online software for residential and small commercial customers:

- Bill analyzer – using actual bill data, this tool will allow customers to perform month-to-month and year-over-year bill analysis to gauge why bill amounts change.
- Energy Audit – using specific details of your home or business, this tool pinpoints energy usage and opportunities to save based on your appliances and age of your home or business.
- Energy Calculators - identifies potential costs savings and energy usage through the purchase of energy efficient appliances.

Small commercial rebates toward energy efficient appliances/products:

- $250 toward a natural gas forced air furnace (90%+ efficiency rating)
- $150 toward a natural gas water heater (75,000 Btu/hr or greater, 88% thermal efficiency or higher)
- $500 toward a natural gas high efficiency booster water heater (80% thermal efficiency or higher)
- $300 toward an ENERGY STAR qualified high efficiency natural gas fryer
- $100 toward a high efficiency natural gas griddle (minimum cooking energy efficiency rating of 38%)
- $100 toward a natural gas convection/conveyor oven (minimum cooking energy efficiency rating of 40%)
- $1,000 toward a natural gas combination oven (minimum cooking energy efficiency rating of 40%, thermostatic control)
- $600 toward a natural gas infrared upright broiler
- $200 toward a natural gas infrared charbroiler
- Up to $5,000* toward a natural gas boiler (various sizes and types)
- Up to $5,000* toward natural gas boiler controls (various types)
- $250 toward natural gas boiler tune-ups

* Vectren rebate may be up to 25% of the purchase price but will not exceed the maximum dollar amount of $5,000.

New home construction rebates toward energy efficient appliances/products:

- $1,000 toward the adoption of ENERGY STAR home standards
- $250 toward a natural gas furnace (90%+ efficiency rating)
- $20 toward an ENERGY STAR qualified programmable thermostat
- $50 toward a natural gas water heater (energy factor of 0.62% or higher)
- $130 toward an ENERGY STAR qualified clothes washer and matching natural gas dryer

*Maximum of 20 homes per builder per calendar year.

Outreach:

From January through March, a public education campaign that combines paid and earned media will outline the rebates and tools and drive customers to action. Rebate forms and lists of qualifying products are available at www.vectren.com or by calling the Conservation Connection hotline at 1-866-240-8476.

In third party research commissioned by Vectren in September 2006 customers indicated education and conservation tools would be beneficial:

- More than 70 percent of Vectren's Indiana customers do not have programmable thermostats;
- While nearly 80 percent indicated an awareness that conservation can save money, nearly 50 percent have still taken no action (including not yet dialing back thermostats);
- Nearly 60 percent said they would be more likely to purchase a more efficient natural gas appliance if they received a rebate.

- more -

Furthermore, the U.S. Department of Energy estimates one in four residential furnaces is more than 20 years old. With nearly 675,000 Vectren gas customers in Indiana, that's nearly 170,000 furnaces that may need to be replaced.

"The average price of natural gas has more than tripled since 2000, and customers have continued to absorb those costs," Ellerbrook added. "This program allows Vectren and the customer to connect on conservation initiatives and work together to lower natural gas bills. It's a win-win situation."

About Vectren
Vectren Corporation (NYSE: VVC) is an energy holding company headquartered in Evansville, Ind. Vectren's energy delivery subsidiaries provide gas and/or electricity to more than one million customers in adjoining service territories that cover nearly two-thirds of Indiana and west central Ohio. Vectren's nonutility subsidiaries and affiliates currently offer energy-related products and services to customers throughout the Midwest and Southeast. These include gas marketing and related services; coal production and sales; and energy infrastructure services. To learn more about Vectren, visit www.vectren.com.

-end-

Conservation Connection

Tools to help you conserve

VECTREN

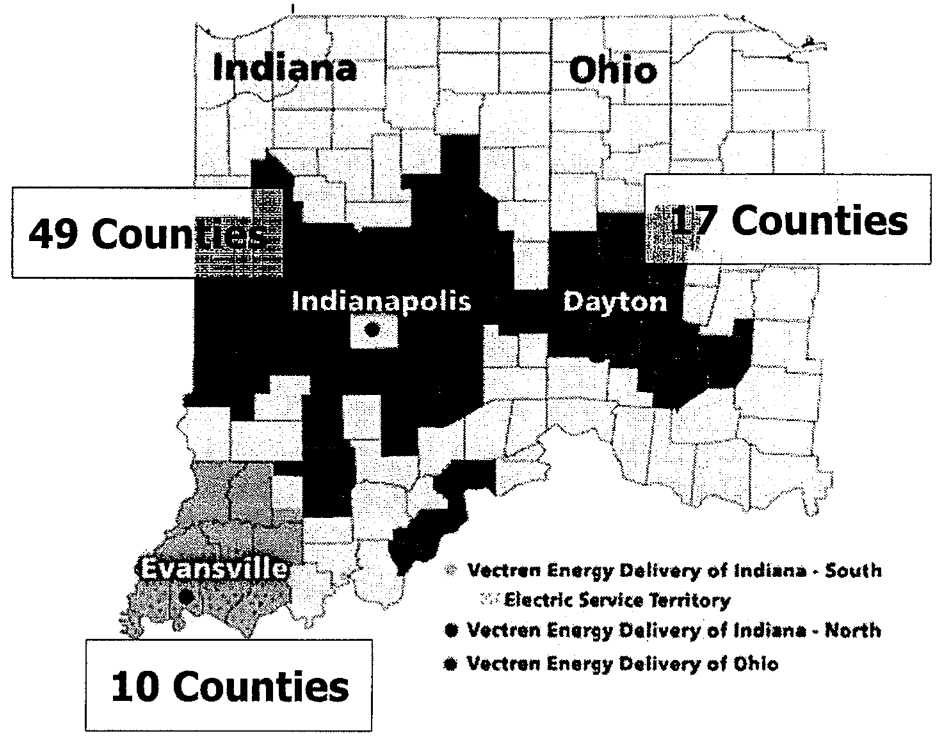
ConservationConnection

About Vectren

Vectren Energy Delivery of Indiana – South
- 112,000 gas customers
- 140,000 electric customers

Vectren Energy Delivery of Indiana – North
- 560,000 gas customers

Vectren Energy Delivery of Ohio
- 318,000 gas customers



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Your Natural Gas Bill

There are two parts to the gas bill.

1. The cost to deliver the natural gas. Shown as "Delivery and Service Charges"
2. The cost of natural gas. Shown as "Gas Cost Charge"

- Vectren Energy Delivery does not profit from gas costs; dollar for dollar pass through.

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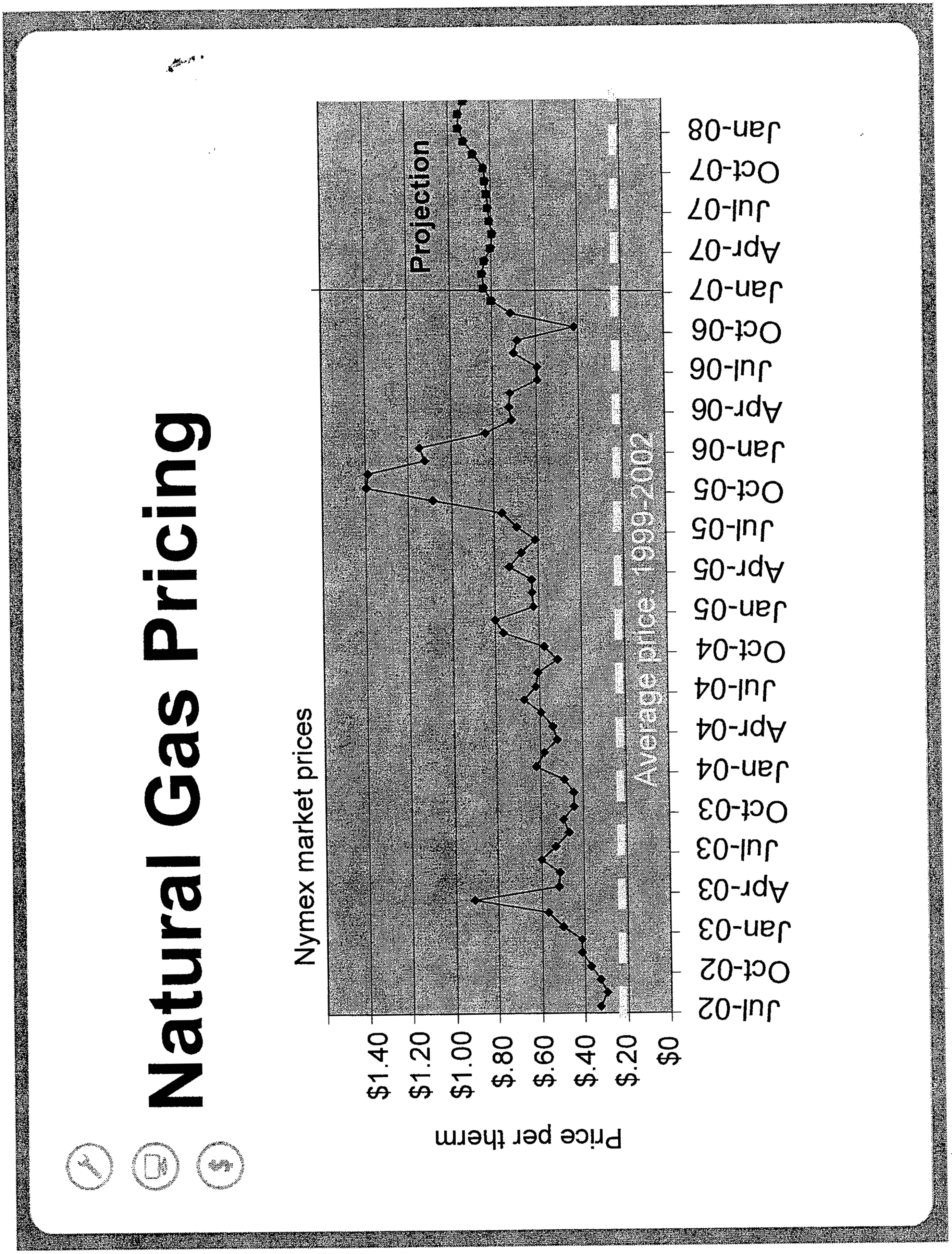
Natural Gas Pricing
Nymex market prices
Price per therm
$1.40
$1.20
$1.00
$.80
$.60
$.40
$.20
$0
Jul-02
Oct-02
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
Jul-05
Oct-05
Jan-06
Apr-06
Jul-06
Oct-06
Jan-07
Apr-07
Jul-07
Oct-07
Jan-08
Projection
Average price: 1999-2002

Impact of High Gas Costs

- Gas costs now represent around 75 to 80% of your bill during the winter.

Gas Cost Charge

75-80 %

Delivery Costs

20- 25%

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The Conservation Connection

- Customers are provided the tools to use less yet the utility can still recover operating costs and earn a fair return

- Tools focus on lowering the gas costs portion of your bill

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ConservationConnection

Now Available!

Conservation tools, resources and rebates for residential, commercial and home builders.

- The Key Elements
  1. Rebates on efficient gas appliances
  2. Online audit and bill analysis tools
  3. Conservation Connection hotline
  4. Financial assistance and payment options

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Public Education

- Combination of paid and earned media
  - Customer education branded as Conservation Connection
    - Focus on rebates and online tools
    - Radio and TV run through March, renew in Fall 2007
  - Newspaper insert and handout for various customer audiences
- Conservation Connection section of Vectren.com
    - Rebates, energy efficiency tips, online tools
- Direct customer communication
  - Energy-grams: emails that provide quarterly conservation tips
  - Enhanced newsletter (bill insert): focused more on conservation

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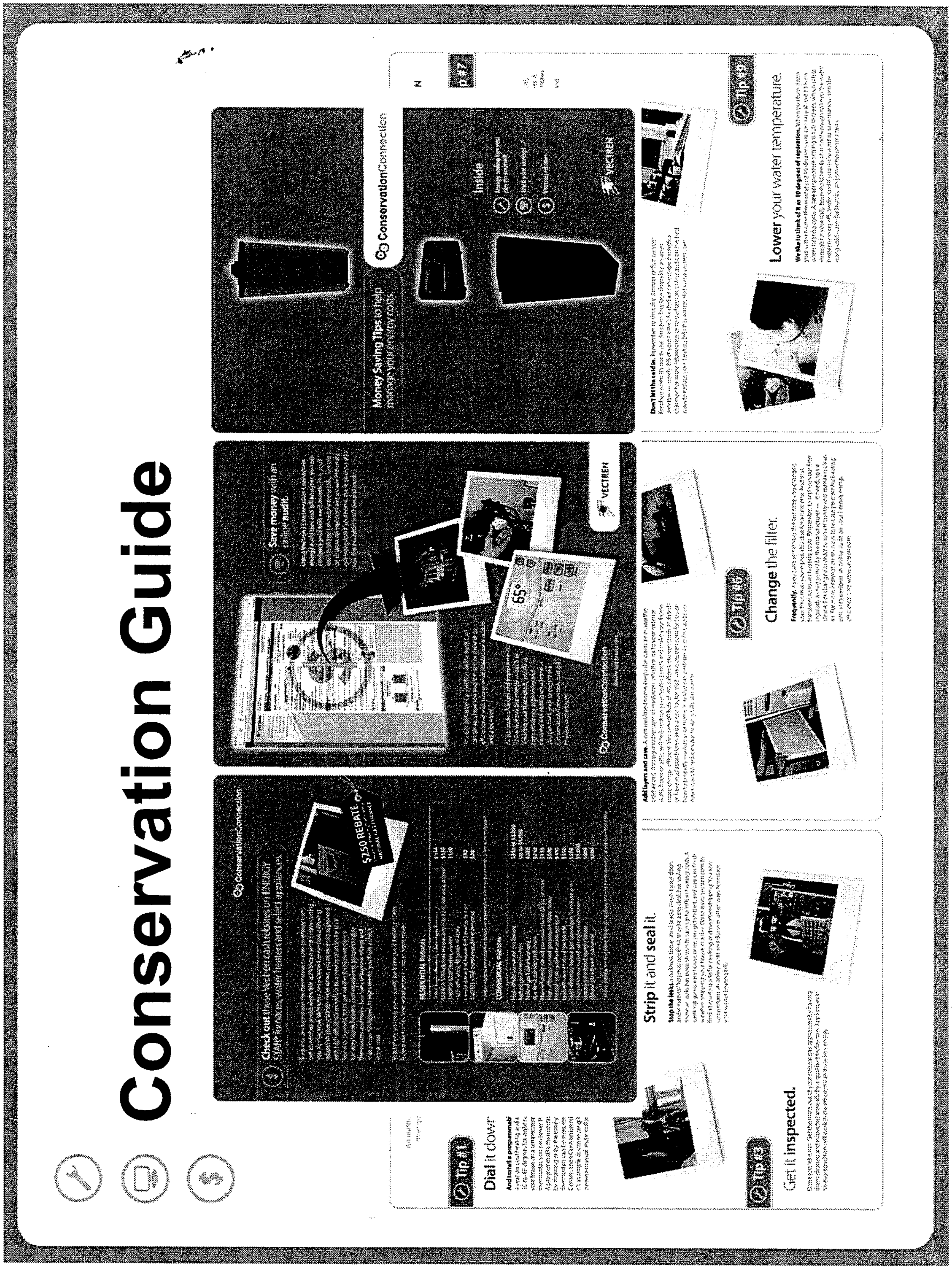
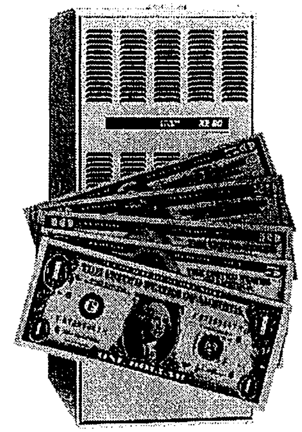
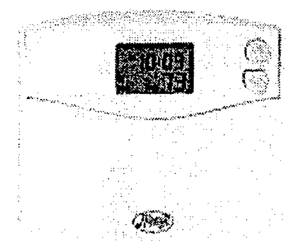

Conservation Guide
Money Saving Tips to help manage your energy costs.
ConservationConnection
Inside
VECTREN
$250 REBATE
65°
Tip #1
Dial it down
Tip #3
Get it inspected.
Strip it and seal it.
Tip #6
Change the filter.
Tip #9
Lower your water temperature.

Residential Rebates





- $250 - gas furnace with a 90%+ efficiency rating
- $20 - ENERGY STAR® qualified programmable thermostat
- $50 – high-efficiency water heater heater
- $130 – ENERGY STAR qualified washer and a gas dryer

- Rebate forms and lists of qualifying products at Vectren.com

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Commercial Rebates

- $250 - gas furnace with a 90%+ efficiency rating
- Up to $5,000 – natural gas boiler
- $150 – high-efficiency water heater heater
- Food service equipment – high-efficiency griddle, convection oven, broiler, booster water heater, **PLUS MORE**.

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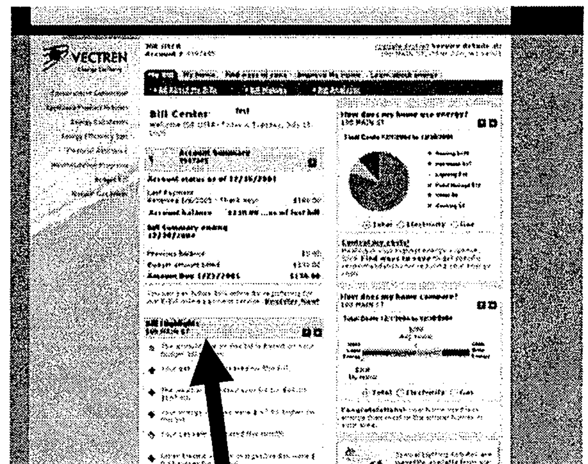
Online Tools

Bill analyzer
- Offers month-to-month and year-over-year analysis to gauge why monthly bills may vary

Home or business energy audit
- Pinpoints energy usage based on your appliances and age of your home or business

Energy Calculators
- Helps determine potential savings by upgrading to high-efficiency appliances



Uses actual bill data

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Conservation Connection Call Center

1-866-240-8476

Speak directly with an energy efficiency expert

- Offers conservation tips
- Can assist with bill analysis and energy audits

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Financial Assistance

EAP/LIHEAP (energy assistance programs)

- State/federal dollars for those that fall within 150% of federal poverty guidelines; median pledge = $225
  - Family of four: $30,000 or less
- Free home weatherization
- Visit local community action agency to sign up

Help Thy Neighbor

- Assistance for those who do not qualify for LIHEAP
- Must fall within 150 to 200% of federal poverty guidelines
  - Family of four: $30,000 to $40,000
- $200 bill credit for those with a disconnect notice or who have been disconnected
- Visit www.vectren.com or call 1-800-227-1376

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Billing and Payment Options

Budget Bill
- Take the yearly bill average and spreads it over 12 months
- Amount is based on previous consumption, normal winter weather and projected natural gas costs
- Enroll at Vectren.com or call 1-800-227-1376

Payment Arrangement
- Pay your total bill in smaller increments over an extended period of time
- Enroll at Vectren.com or call 1-800-227-1376

Payment Extension
- Extend the due date of your bill to avoid late fees
- Enroll at Vectren.com or call 1-800-227-1376

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Summary

- Natural gas prices will likely remain high
- Conservation is the single best way to lower your bill, no matter what the season
- Take advantage of the Conservation Connection to help you conserve
- You can lower bills without sacrificing comfort

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ConservationConnection


Conservation Connection
www.vectren.com
1-866-240-8476
VECTREN
ConservationConnection

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Indiana ScoreCard: February 2007

Appliance/Product/Service Rebates

Appliance	Feb. Rebates	$ Awarded	Rebates since Dec. 1	Total $ Awarded	Annual Estimate Therm Savings
Furnace - R	229	$57,250	498	$124,500	39,342
Water heater - R	10	$500	25	$1,250	1,250
Prog. thermostat - R	131	$2,620	313	$6,260	10,955
Washer - R	92	$9,200	188	$18,800	5,640
Washer/Dryer - R	17	$2,210	28	$3,640	1,204
Furnace - NH	3	$750	5	$1,250	395
Water heater - NH	1	$50	2	$100	100
Prog. thermostat - NH	10	$200	13	$260	455
Washer - NH	2	$200	5	$500	150
Washer/Dryer - NH	2	$260	2	$260	86
Furnace - C	11	$2,750	19	$4,750	1,501
Boiler - C	0	$0	1	$1,175	2,560
Boiler tune-up - C	0	$0	4	$1,000	5,808
Water heater - C	2	$50	2	$100	1,200
TOTALS	510	$76,290	1,101	$164,045	70,646

R = residential   C = commercial   NH = New home construction

Conservation Connection Call Center

	February	Previous Month	Year-to-Date
Direct Calls	1,023	578	1,601
Transferred Calls	2,410	2,767	5,177
Total Calls	3,433	3,345	6,778

Speakers Bureau Engagements

Timber Park Neighborhood Association, Evansville
Plainfield Optimist Club
Vanderburgh County Council, Evansville
Vanderburgh County Commissioners, Evansville
Jefferson County Commissioners, Madison
21st Century School Parents - EVSC, Evansville
Senior and Family Services, Washington
Civitan Club, Vincennes
Evansville JayCee's

Feb. Presentations	Presentations Year-to-Date	# of People Reached
9	11	230

Other Public Events:
Indiana Energy Efficiency Summit
IURC Technical Conference

Earned Media

Includes newspaper, TV and radio clips as well as live or recorded interviews.

Terre Haute Star Tribune
Evansville's ABC News 25
Fountain County Neighbor
Hartford City News-Times
Evansville Courier & Press
Evansville's NBC 14
Muncie Star Press
Martinsville Reporter

Media Hits Year-to-Date
25 to 30

Conservation Connection ScoreCard

Nexus - Online Tools

Bill Analyzer and/or Energy Audit - The Nexus software offers two unique tools, the Energy Audit and Bill Analyzer, to help address billing questions and offer tips to lower bills. A customer must log in to use either tool, and one visit is logged regardless of which (or both) tool is utilized.

	February	Year-to-Date (since Dec. 7)
Total unique (first-time) users	9,706	21,385
Total new users	7,815	18,719
Total return users	3,671	6,838

eGram (EnergyGram) Enrollment - Upon completion of the Energy Audit, customers can opt in to receive a quarterly eGram, which provides user-specific efficiency tips and related information via email.

	February	Year-to- Date
Total Enrollments	777	1,871

Bill Analyzer Pop-Up Survey Results - While using the Bill Analyzer tool, an optional pop-up survey will randomly appear. This survey will not be shown more than once to each customer.

	February	Previous Month
Respondents	43	56
% satisfied with tool	82%	91%
% that found it helpful in addressing billing questions	77%	75%
% who will use it again	81%	80%

WECC Activities

This section tracks personal contacts made through Wisconsin Energy Conservation Corporation (WECC) to HVAC dealers, distributors, retail outlets, etc to get them to place/promote Conservation Connection materials.

Personal Contacts	February
HVAC distributors	22
Food service distributors	9
Heating dealers	4
Big box retail outlets	17

Home Builder/Trade Ally - Sales & Marketing Activities

This section tracks Conservation Connection messages distributed through home show events, trade show booth opportunities and one-on-one or group meetings with builders or other trade allies.

Southwestern Indiana Builder's Association, 150 people
Building Sciences Workshop (SIBA), 70 people
Builders Association of Greater Lafayette Builder Expo Trade Show, 500 booth contacts
River Valley Home Builders of Madison, 30 attendees
Professional Heating & Cooling Contractors, 15 to 20 attendees

Personal Contacts	February	Previous Month	Year-to-Date
Home builders	62	61	123
Food service	10	16	26
HVAC	12	34	46

ConservationConnection

Indiana ScoreCard: March 2007

Appliance/Product/Service Rebates

Appliance	March Rebates*	$ Awarded	Rebates since Dec. 1	Total $ Awarded	Annual Estimated Therm Savings
Furnace - R	134	$33,500	831	$207,750	65,649
Water heater - R	10	$500	51	$2,550	2,550
Prog. thermostat - R	130	$2,597.50	615	$12,297.21	21,525
Washer - R	66	$6,600	375	$37,500	11,250
Washer/Dryer - R	10	$1,300	53	$6,890	2,279
Furnace - NH	2	$500	14	$3,500	1,106
Water heater - NH	1	$50	4	$200	200
Prog. thermostat - NH	0	$0	14	$280	490
Washer - NH	0	$0	7	$700	210
Washer/Dryer - NH	0	$0	2	$260	86
Furnace - C	10	$2,500	34	$8,500	2,686
Prog. thermostat - C	2	$40	2	$40	162
Boiler - C	0	$0	1	$1,175	2,560
Boiler tune-up - C	0	$0	4	$1,000	5,808
Water heater - C	1	$150	1	$150	600
TOTALS	366	$47,737.50	2,008	$282,792.21	117,161

R = residential C = commercial NH = New home construction
* Denotes the month in which the appliance was installed/purchased, not the month in which the rebate was processed.

Conservation Connection Call Center

	March	Previous Month	Year-to-Date
Direct Calls	598	1,023	2,199
Transferred Calls	1,708	2,410	6,885
Total Calls	2,306	3,433	9,084

Speakers Bureau Engagements

Vincennes Kiwanis Club
Historic Newburgh Kiwanis

March Presentations	Presentations Year-to-Date	# of People Reached
2	13	270

Earned Media

Includes newspaper, TV and radio clips as well as live or recorded interviews.

Indiana News 9, Clarksville
Mt. Vernon Democrat
Hartford City News-Times

Media Hits Year-to-Date
30 to 35

Nexus - Online Tools

Bill Analyzer and/or Energy Audit - The Nexus software offers two unique tools, the Energy Audit and Bill Analyzer, to help address billing questions and offer tips to lower bills. A customer must log in to use either tool, and one visit is logged regardless of which (or both) tool is utilized.

	March	Year-to-Date
Total unique (first-time) users	7,328	28,713
Total new users	5,007	23,726
Total return users	3,379	10,217

eGram (EnergyGram) Enrollment - Upon completion of the Energy Audit, customers can opt in to receive a quarterly eGram, which provides user-specific efficiency tips and related information via email.

	March	Year-to- Date
Total Enrollments	479	2,350

eGram Survey Results - A survey was included with the first eGram regarding the online Energy Audit.

	March
Respondents	388
% that found it helpful in in identifying opportunities for energy savings	78%
% that plan to implement some of the savings tips	88%
% who believe they can save money on their bills by reducing gas consumption	93%

WECC Activities

This section tracks personal contacts made through Wisconsin Energy Conservation Corporation (WECC) to HVAC dealers, distributors, retail outlets, etc to get them to place/promote Conservation Connection materials.

Personal Contacts	March	Year-to-Date
HVAC distributors	59	86
Food service distributors	2	18
Heating dealers	4	10
Independent appliance stores	10	12
Big box retail outlets	83	105

Home Builder/Trade Ally - Sales & Marketing Activities

This section tracks Conservation Connection messages distributed through home show events, trade show booth opportunities and one-on-one or group meetings with builders or other trade allies.

Monroe County Home Builders Association, 100 in attendance
Southwestern Indiana Builder's Association, 191 in attendance
Home Builders Association of Southern Indiana (table-top display), 700 in attendance
Gibson County Builders Association, 20 in attendance

Personal Contacts	March	Year-to-Date
Home builders	46	169
Food service	22	48
HVAC	14	60